IMPLEMENTATION OF INTELLIGENT WELL TECHNOLOGY TO MAXIMIZE HYDROCARBON PRODUCTIVITY FROM MULTI-LAYERED RESERVOIR

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CERTIFICATION OF APPROVAL

Implementation of Intelligent Well Technology to Maximize Hydrocarbon Productivity from Multi-layered Reservoir

By

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Approved by,

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CERTIFICATION OF ORIGINALITY

This is to certify that we are responsible for the work submitted in this project, that the original work is our own except as specified in the references and acknowledgement, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

MOHAMMED AMINE MEDBOUB

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ABSTRACT

Intelligent Well Technology (IWT) consists of flexible remotely actuated flow rate control systems with permanent downhole gauges to permanently monitor the production and/or injection variables, take actions in real time, reducing well count and intervention expenses. This alternative is significantly more efficient than the traditional completions, consisting of selective completions that require expensive subsea interventions to close one zone and open another. Also IWT balances the drawdown along the wellbore while, accelerating production by extending the plateau period and decreasing the decline rate while delaying the unwanted fluid breakthrough.

This project presents single well application of IWT using multi-layered reservoir models, in this model the normal reservoir engineering duty was performed, e.g. well location and design which then included when IWT is applied to this model. The Intelligent wells will be used to increase productivities in a less expensive manner.

Starting from 1997 with the first intelligent well implementation in the Gulf of Mexico which has been successfully used, several hundred wells have been completed with inflow control valves (ICVs) and downhole monitoring systems in new and mature fields across the world. Today, the applications of this technology are available for a vast range, i.e.: in gas reservoirs, deep water, heavy oil reservoir, tight reservoir, and even for Extreme Reservoir Contact (ERC) which are intelligent multilateral wells.

A pipesim simulation was conducted to investigate the benefit of IWT application in multi-layered reservoirs, in terms of maximising oil productivity as compared to the conventional well. The study was focused into optimizations studies.

The primary objectives of the optimizations part were to develop an optimum inflow control valve (ICV) choking policy to commingle two reservoir layers in a single well, with different reservoir parameters and without any crossflow between layers.

The results from optimizations part show that the optimum choking policy for IWT improved the oil productivity compared to the conventional well.

This project concluded to that IWT can improve the reservoir management once the performance of the reservoir simulation model is correctly understood and powerful optimisation tools are used.

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LIST OF ABBREVIATIONS

STOIIP	Stock Tank Oil Initially in Place (STB)
GIIP	Gas Initially in Place (SCF)
HIP	Hydrocarbon in Place
BCF	Billions of Cubic Feet
BHP	Bottom Hole Pressure (psi or bar)
BOPD	Barrel of Oil per Day
BU	Build Up test
FBHP	Flowing Bottom Hole Pressure (psi or bar)
GOC	Gas-Oil-Contact (ft or m)
GOR	Gas Oil Ratio (scf/stb)

ICOS	Intelligent Completion Optimization System
ICV	Interval Control Valve
ID	Internal Diameter (ft or m)
I-well	Intelligent Well
IWT	Intelligent Well Technology
P	Pressure (psi or bar)
S	Skin factor
STB	Stock Tank Barrel
THP	Tubing Head Pressure (psi or bar)
TVD	True Vertical Depth (ft or m)
VFP	Vertical Flow Performance

LIST OF SYMBOLS

A	Cross Sectional Area (ft^2)
K	Permeability in milliDarcy
ΔP_{choke}	Pressure loss across a choke (psi)
ID	Casing inner diameter (ft or m)
L	Length of Tubing in the Choke Segment (ft or m)
Q_n	Flow Rate from Zone n (STB/day)
V	Fluid Flow Velocity (ft/s)
V_P	Flow velocity through the choke segment (ft/s)

CHAPTER 1

INTRODUCTION

1.1 Background of Study

Field development often start with evaluation of the size of the reservoir, how much it will produce for how long, how many wells are needed for both producers and injectors, and how much each well has to produce. An overview of the steps require for field development is presented in Figure 1.1.

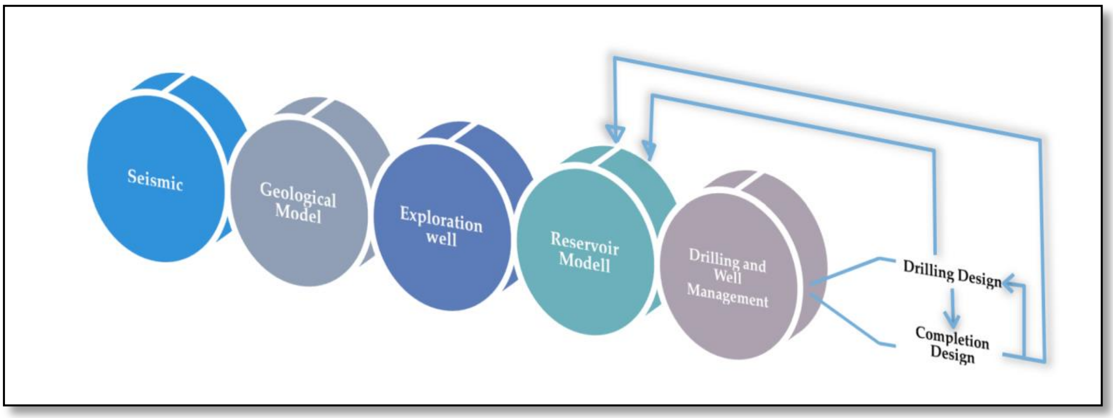


Figure 1.1: Elements in field development

In order to optimize the oil and gas production which has the major impact on the economic capability of the field, this project will cover the implementation benefits of the intelligent well completion.

Intelligent-well completion (IWC) is a developed technology that allows operators to optimize reservoir management and field facilities performance through the Downhole Interval Control Valves (ICVs) and real time temperature/pressure sensors. IWC also used to reduce the number of wells to be drilled in field by commingling many producing zones together in same well.

ICVs are capable of managing wellbore friction effects due to the flowing of produced fluid as well as the above differences in zone pressure along the wellbore. Oil recovery factors improve and produced water volumes reduce with a correct valve choking, when combined with proper selection of the ICV location(s) and control zone interval. However, the degree of improvement is dependent on the reservoir type (Layered, Faulted, and Channelized) and the distribution of porosity and permeability within it.

1.2 Problem Statement

Berlian East field is actually containing reservoir with multi-layers and with different reservoir rock parameters as well, so in order to to commingle two reservoir layers in a single well, with different reservoir parameters and without any crossflow between layers which are M 7/8 and M 2/3. We need to develop an optimum inflow control valve (ICV) choking policy. And this can be done by opening and closing the choke from both layers using “pipesim simulator”.

1.3 Objectives and Scope of Study of Project

This project aims to evaluate the impact of the intelligent completions on the reservoir development by using up-to-date modeling and optimization techniques. It will highlight the experiences gained by studying the application of IWT to a field example. These experiences can be used by a reservoir engineer when faced with having to make a decision for development investment which makes even more profit in the future. The objectives of our study are as follows:

- Determine the appropriate optimization settings of two variables that could enhance the benefit of IWT application in this type of reservoir. These variables are:

  a. Tubing size, perforation interval and tubing head pressure,

  b. ICV placement and flow area (Ac) opening.

- Application of an economic evaluation to confirm the potentially "Add Value" to the field by installation of smart wells, by doing an economic analysis for the particular case being studied.

CHAPTER 2

LITERATURE REVIEW

2.1 Introduction

In this project the term "Intelligent Well Technology" (IWT) will refer to completion of the well with Interval Control Valves (ICV) combined with sensors of the flow parameters via pressure, temperature and multi-phase flow meters. This "state-of art" well completion technology provides greater flexibility to monitor and control wells without well intervention. (Williamson, et al. 2000).

The benefit of IWT application in a multi-layered reservoir can be evaluated from several different perspectives such as; total oil recovery, oil production, time of water breakthrough, total water cut, economic cost reductions from water handling, well activities, etc. However, this study focuses on the potential benefits of IWT application via direct control of ICVs in multiple completions in a single wellbore in term of maximizing oil productivity. The ICV control was based on variable choking.

2.2 Brief Overview of Berlian East Field

The Berlian East Structure, located offshore to the east coast of Peninsular Malaysia is considered for development. Figure 2.1 shows the location of the structure. From Figure 2.1 it can be deduced that the Berlian East Structure is located in the Penyu Basin.

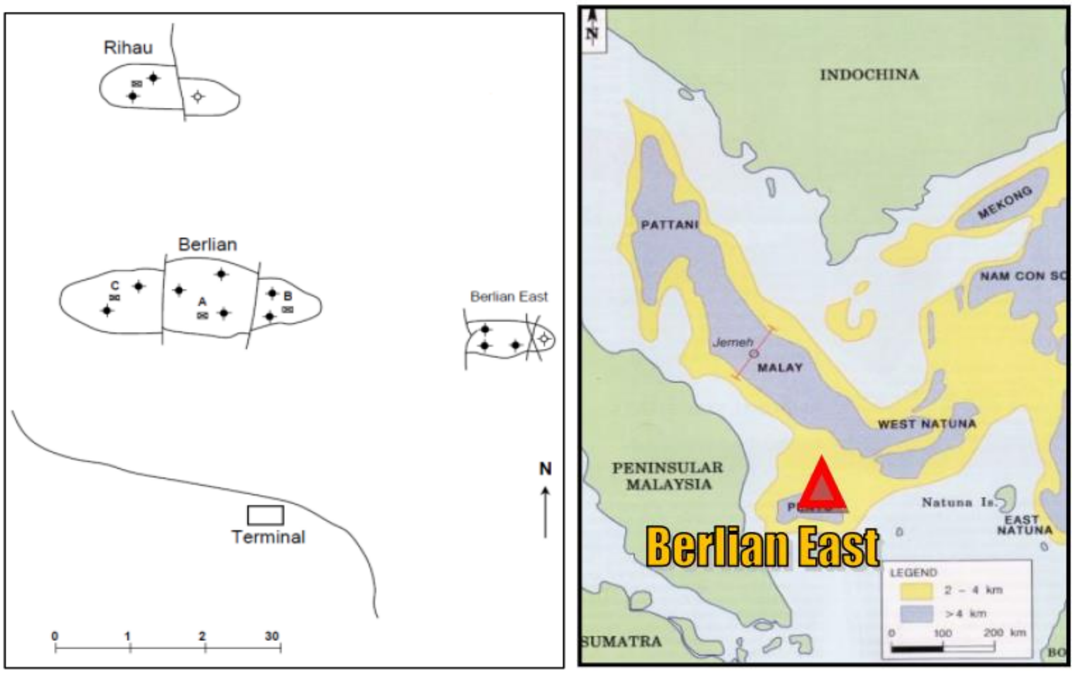


Figure 2.1: Berlian East Location at Penyu Basin (The Petroleum Geology and Resources of Malaysia). [1]

As shown in Figure 2.1, the Berlian East field is located 25 km offshore of peninsular Malaysia in the water depth of 76 meters, it is having a length of 11 km and almost 5 km wide with East-West trending faulted line. The field was discovered by well Berlian East-1 that was drilled in late 1999 in Block-1.From the 2D seismic grid shot in 1999 an anticlinal feature was interpreted which was basis for the location of well and the objective of well was to assess the quality of the reservoir and hydrocarbon potentials of the block. Due to striking normal faults this field is compartmentalized into four fault blocks. The Berlian East anticline is divided by several normal faults having a vertical displacement ranging from a few meters up to 100 meters. The disappointing result of Berlian East-2 confirms that intra-field faults are sealing faults.

As shown in Figure 2.2, this structural cross-section was conducted between BE-1 in block 1 to BE-2 in block 4. From this figure, it can be seen that the fault structure is dipping towards the east. It is also useful to understand the trapping mechanism of hydrocarbons presents in the field.

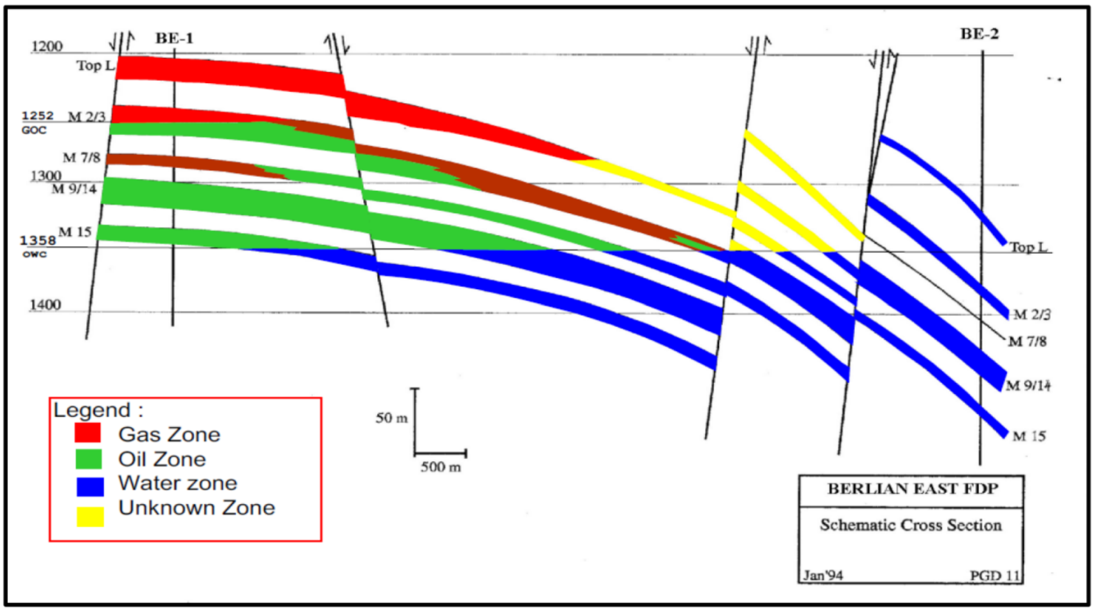


Figure 2.2: Structural Cross Section of Berlian East field. [2]

Berlian East field is evaluated deterministically where the STOIIP and GIIP estimation is divided into three categories namely the minimum case most likely case according to the average porosity and average hydrocarbon saturation variations. Table 2.1 shows the summary for STOIIP and GIIP calculated for all three cases.

Table 2.1: Summary for STOIIP and GIIP calculated for all three cases. [2]

Cases (s)	STOIIP (MMstb)	GIIP (Bscf)
Minimum Case	248.78	66.56
Most likely case	288.88	94.36
Maximum Case	325.48	134.90

Figure 2.3 below is showing the oil and gas contribution from each layer to the total amount of STOIIP and GIIP of the whole field of interest.

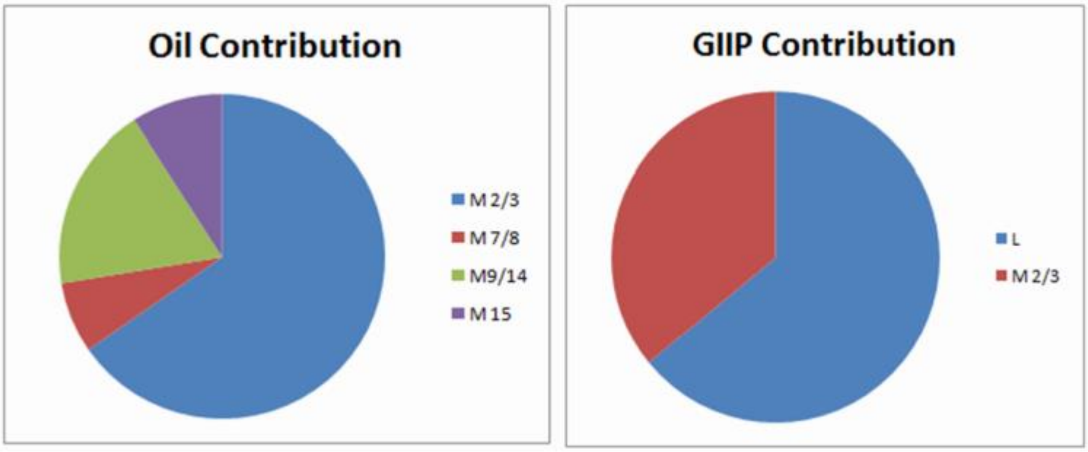


Figure 2.3: Oil Contribution and GIIP Contribution. [2]

The initial reservoir pressure (P_r) is 1854 psig and the bubble point pressure (P_b) 1332 psig. Since the reservoir pressure is higher than the bubble point pressure, the reservoir is categorized as an undersaturated reservoir which means all gas exist in solution.

This study concentrates on simple onlap type of turbidite deposits in multi-layered reservoirs. The reservoirs are commonly characterized by laterally extensive sandstones separated by thin shale or argillaceous inter-beds, typically less than 25 cm thick. The argillaceous beds may be deposited from low-density turbidity current events, low density muddy turbidites or pelagic and hemipelagic settling of fine-grained materials between sandy turbidity current events.

From the reservoir data and well test results, it can be concluded that the reservoir fluid type is made up of light crude oil since it is greater than 31.1˚API. Based on single state separator test, it can be confirm reservoir model is Black oil model [2]. Also from well test result, it was found that the water cut is 0 % which indicates that well tested (BE-1,BE-3, BE-4) located at a weak aquifer region or as the reservoir depletes, the water will start moving in from an active aquifer (if present) to displace the oil and expand the aquifer energy.

Figure 2.4 shows the locations of the four exploration wells that have been drilled in BE field, while Figure 2.5 below show the locations for the entire wells (production/injection) of BE Field.

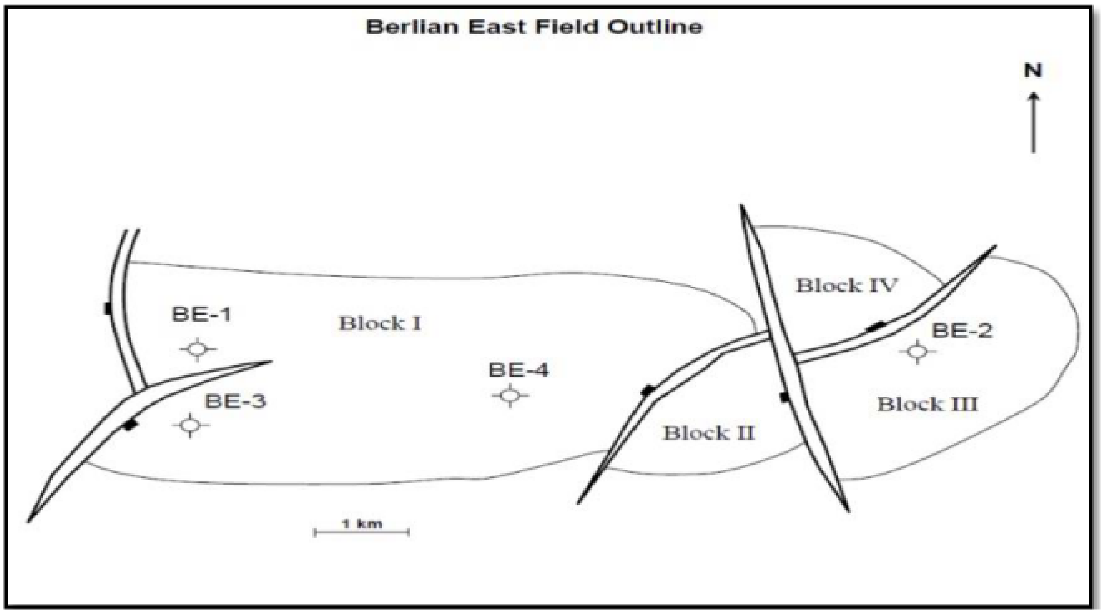


Figure 2.4: The Berlian East Field Outline. [2]

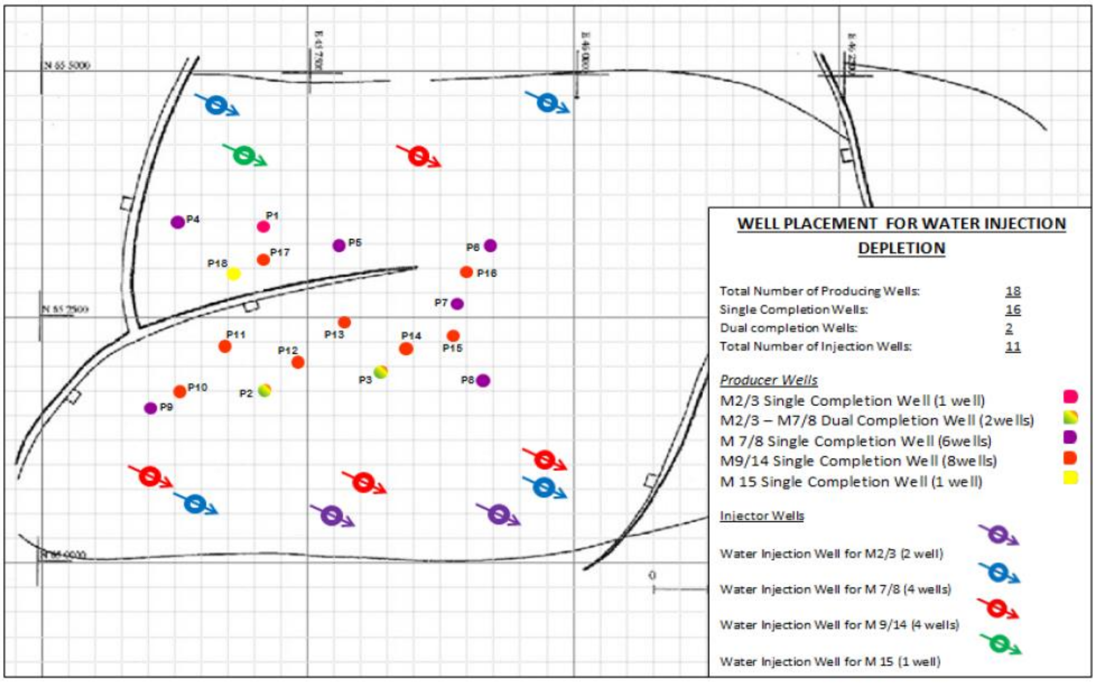


Figure 2.5: Placement of (production/injection) wells in a Berlian East Field. [2]

2.3 Nodal Analysis of the Production System

Nodal systems analysis, which has been applied to many types of systems, consists of choosing a point or node in the producing system (well and surface facilities). Equations for the relation between flow rate and pressure drop are then developed for the well components both upstream of the node (inflow) and downstream (outflow). The flow rate and pressure at the node can be determined since:

- Flow into the node equals flow out of the node,
- Only one pressure can exist at the node.

At any time, the pressure at the end points of the system {separator (P_{sep}) and reservoir pressure P_R both of them are fixed (HW manual, 2012). Thus:

P_R - (Pressure loss upstream components) = P_{node}

P_{sep} + (Pressure loss downstream components) = P_{node}

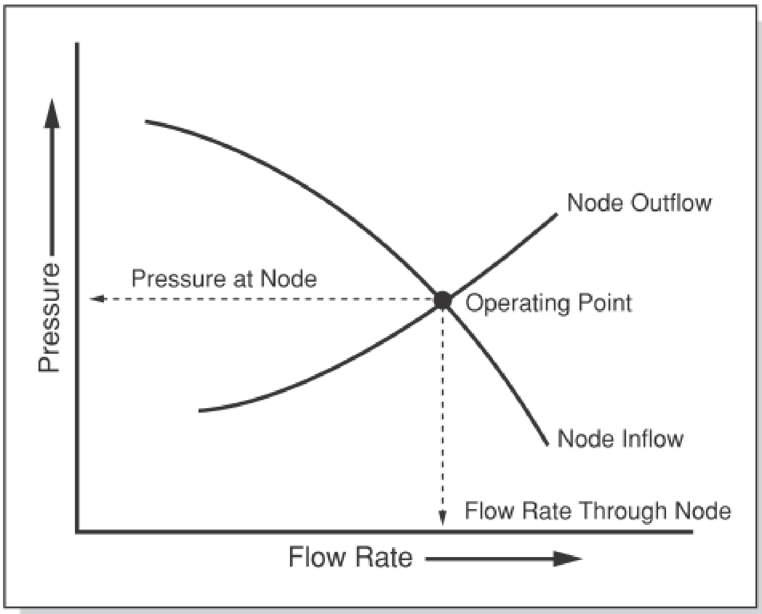


Figure 2.6: Node flow rate and pressure

The intersection of these two lines (inflow/outflow) is the known as operating point; this defines the pressure and rate at the node.

Liquid Inflow Field measurements have shown that wells producing undersaturated oil (no gas at the wellbore) or water have a straight line IPR (Figure 2.7)

$Q = PI\ (P_R - P_{wf})$ Equation (2)

Where Q is the flow rate and PI the Reservoir Productivity Index, i.e. the well inflow rate per unit of well drawdown.

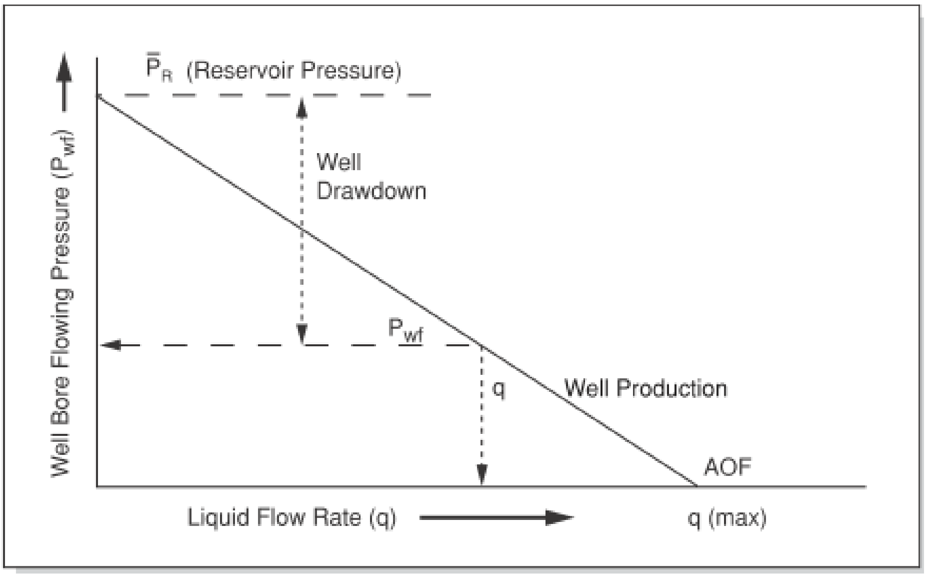


Figure 2.7: Straight-line IPR (for an incompressible liquid)

The well's inflow potential can then be calculated at any draw-down (or P_{wf})

Tubing outflow performance starting from top of the well to the bottom, including all the parameters which contribute to the pressure loss at the bottom of the well are (HW manual, 2012):

- The (back) pressure at the wellhead (tubing head pressure),
- The hydrostatic head pressure between the wellbore and wellhead. This is a function of the change in elevation between the wellhead and the wellbore point and the average density of the fluid in tubing all multiplied by the acceleration due to gravity,

- The pressure loss required to overcome friction losses due to viscous fluid. This depends on the fluid's flow velocity, flowing regimes as well as the length, roughness and diameter of the tubing.

2.4 Brief Overview of Intelligent Well Technology

2.4.1 What is Intelligent Well system Technology

Intelligent completion techniques have gained a great deal of attention because of their abilities to improve monitoring and overall well performance in oil and gas field developments. In such multi-zone intelligent-well completions, flow adjusting or Interval Control Valves (ICVs) and monitoring devices are placed between zonal isolation packers to control flow into or out of each perforated zone.

IWT is determined as" a completion system capable of collecting, transmitting, and analyzing wellbore production, reservoir, and completion-integrity data, then enabling remote action to improve reservoir control and well production performance". Figure 2.8 shows overall components of IWT completion.

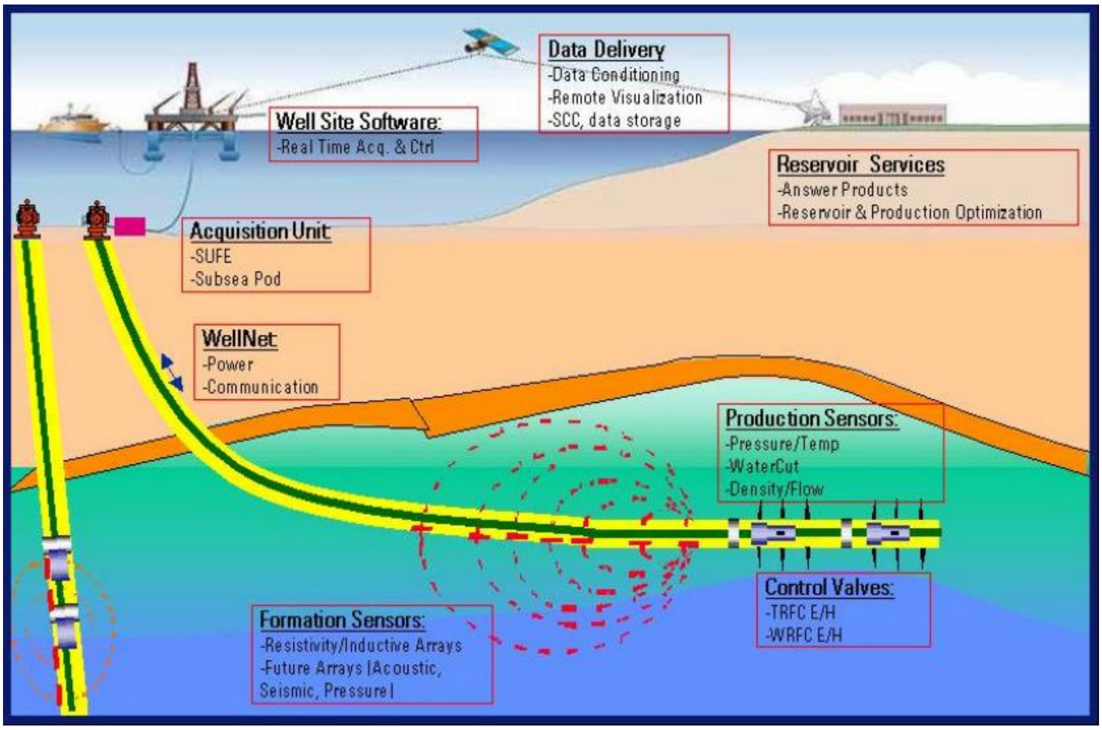


Figure 2.8: Overall IWC system including production sensors, formation sensors, and associated control valves. [10]

The "Intelligent Well" is a well with "the ability to install, operate, monitor and control the completion's operation without the need for conventional interventions", so the overall project value will increase because of significant reductions in expenses of intervention, well services, infill drilling, water handling capacity, etc. Intelligent completions are focused on the delivery and management of production flexibility. The significant benefits of "Intelligent Wells" summarized as follows:

- Increasing the oil recovery by management of reservoirs (making available real time information) from the downhole producing zones. This can helps the operators to make decisions on the choke settings required in order to get an optimum well performance,
- Reducing the cost of oil production by reducing the number of the both light and heavy well interventions during the field life time,
- Minimizing the cost (and risk) of zonal isolation allows for more proactive and regular reservoir management and then could increase hydrocarbon reserves,
- Providing zonal well testing (ideally with zone specific downhole pressures) by sequencing intervals open and closed,
- Let the operators to reconfigure well architecture without well intervention, and this will increase the well's economic net present value (NPV) predominantly by increasing the well reserves,
- Automate production operations permitting production staff to be located remote from the well itself e.g. on land rather than offshore, with the resultant reduction in staff costs and potential increase in staff productivity and safety,
- Improving the ability to clean-up the well. For example, the toe of a long, high-angle well can be selectively produced, hence provide a greater drawdown and best clean-up characteristics than a commingled producer,
- Decrease the number of wells required e.g. produce simultaneously from multilayer reservoir zones with incompatible pressures etc.
- IWT reliability has to exceed 95% operability 15 years after installation.

2.4.2 Intelligent Well System Technology

An "intelligent well" is a well with "the ability to install, operate, monitor and control completions without the need for conventional interventions". It will have some of the following attributes:

- A multi-lateral or multi-zone well producing from 1 percent or more reservoirs, e.g. using of produced gas to accelerate oil production as a form of artificial lift completion,
- A well producing single or multiple zones into one wellbore, leading to commingled production from different zones and lateral wellbores,
- A well with the ability to control the production flow by a down-hole choke. This can achieve by real time monitoring and control of the producing zones using an Inflow Control Valves (ICV) and an optimized sensor distribution for data acquisition and down-hole fluid production measurement. It also has the flexibility to shut-off water/gas producing zones at the wellbore at any time,
- A well with some form of artificial lift installed. The type of lift selected depends on the reservoir and production system requirements. Frequently, an ESP is installed down-hole to lift the produced liquid.

Figure 2.9 shows a simple feedback control system for a well design. Outputs of the monitoring system are pressure, oil, gas and water rate, etc. Short-term control (e. g. aiming at keeping the net oil production rate constant) can be made based on these parameters. Long-term control (production forecasting and reservoir management) requires a reservoir model whose validity is checked at uniform intervals. Information from production engineering activities such as stimulation, water or gas shut off, etc. can also be used in such cases. Well test results, reservoir fluid distribution images from time-lapse seismic or other sources are also used as input to guide the adjustment of the reservoir model.

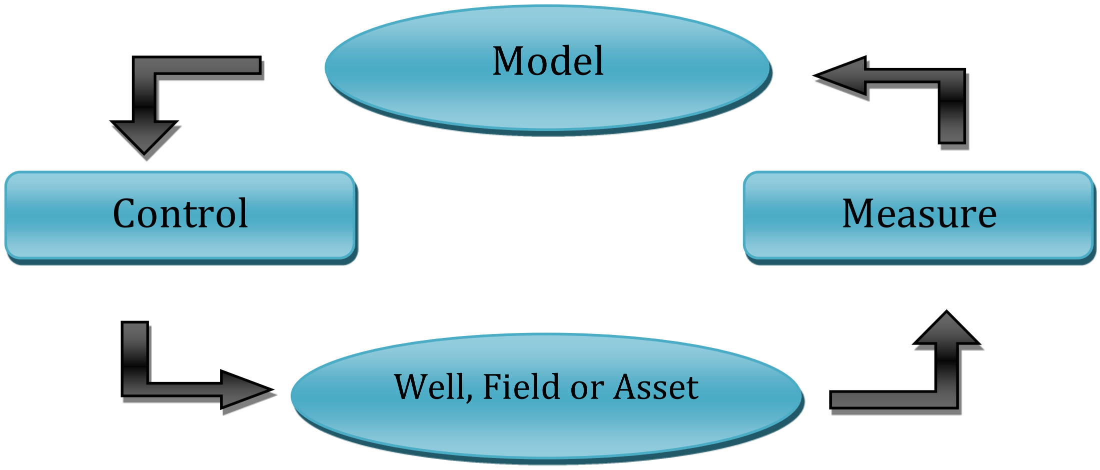


Figure 2.9: Value Loop for Downhole Instrumentation & Control Systems. [5]

Downhole measurements improve the quality of the data compared to measuring devices sited at the surface. Downhole control allows rapid and immediate reaction in the case, for example, of water or gas breakthrough.

Electronic sensors have historically been the most widely used permanent downhole monitoring technology. The susceptibility of electrical systems to failure increases at high downhole temperatures as depth of the well increase. Optical sensing technology now offers an alternative to electronic tools, although the current optical systems do not always deliver the accuracy and resolution of electronic devices.

An optical fiber 2.10 is a circular waveguide that takes the form of a long thin strand of glass same as the diameter of a human hair (0.125mm). This fiber contains two concentric glass regions with slightly changing in refractive indices.

The refractive index is the ratio of the speed of light in a vacuum to its speed in the glass fiber medium. Most of the light travels through the center (core), the outer, lower refractive index than the inner region is called the cladding. Plastic coating and an encasing cable structure protects the optical fiber during installation and operation.

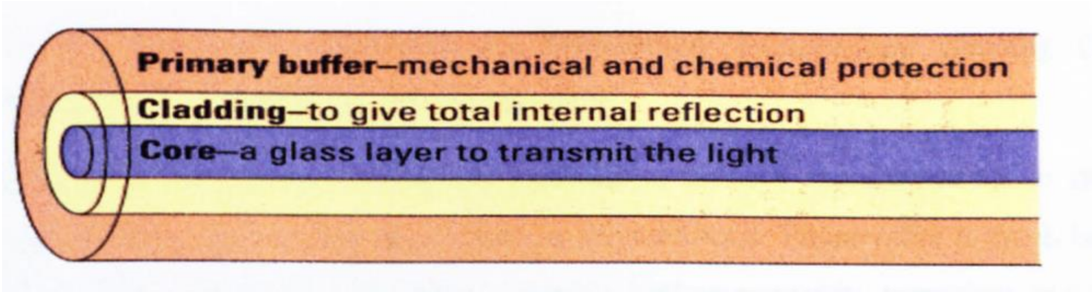


Figure 2.10: The completed optical fiber showing fundamental component layers. [7]

There are two basic optical fiber types: single-mode or multi-mode. The main between them is that the difference is the dimension of the fiber core. A single-mode fiber typically has a core diameter of 0.01 mm, which allows only one mode of light at any time to propagate through the core. While multi-mode fiber has a much larger core (usually 0.05 mm of diameter), allowing hundreds of modes of light to move through the fiber simultaneously.

The single optical fiber is used to measure downhole temperature, pressure, flow rate, and phase fraction. A laser located at surface sends a pulse of light, which is reflected from a numbers of downhole sensors. There are various techniques used to measure pressure and temperature using optical fibers like Bragg Gratings for point sensing, Raman Scattering for Distributed Temperature Sensing, etc.

The optical data is obtained and transmitted in real time to a demodulation unit located at the surface, where it is analyzed using signal processing techniques. Maximum operating conditions for optical sensors are currently up to 150°C and 20,000 psia. Figure 4.13 in the appendix shows the IWC Implementation Overview. [12]

2.4.2.1 The Interval Control Valve

The main objectives for a Downhole Interval Control Valve (ICV) are control, including shut-off, of the flow-rate for a producing zone or well lateral while a surface choke typically operates at lower to medium pressures. These lower pressures cause the surface chokes to be exposed to higher fluid velocities and harsher erosional and corrosion conditions.

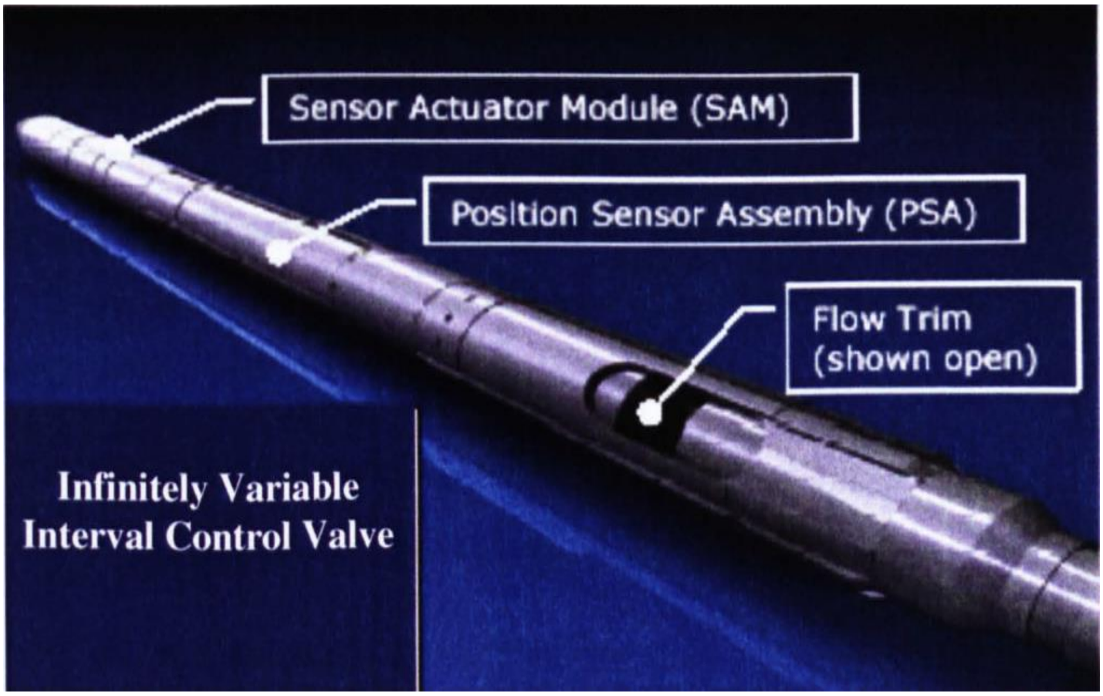


Figure 2.11: An Interval Control Valve (Courtesy of Ippoliti et al)

Surface chokes, unlike ICVs, not only control the flow rates but are also designed for a huge pressure drop so that they can act as a safety device to protect the downstream equipment from corrosion and high pressure (with its lower pressure rating than the wellhead and completion).

The sub-critical (normal) operating range of an ICV shows a non-linear relationship between the flow-rate and the differential pressure applied. Here, the ICV operates in turbulent flow. This can be described by the equation:

$$\Delta P = (Q / Cv)^{n} \qquad \text{Equation (1)}$$

Where:

ΔP is the differential pressure across the valve,

Q is the flow rate,

C_v is the valve flow coefficient (a calibration factor),

n is typically between 1.8 and 2.1.

Infinitely variable and multi-position ICVs are designed to give a flexibly and accurately control the flow over a wide range of flow rates. At the same time the pressure loss across the valve should be reduced to conserve energy; e.g. fluid flowing at 30,000 b/d with a 200 psi pressure drop across it will consume around 102 horsepower. This is not only a waste of reservoir energy, however is also a source of equipment wear and tear. [6]

The above equation indicates that:

- The pressure drop may become unacceptably high at high production rates,
- Sensitive control of the flow rate requires a small value of Cv. but, this will increase the pressure drop for a given rate.

The acceptable pressure drop value from a well performance point of view will depend on the reservoir deliverability and the production tubing/casing performance. It will be controlled by the ICV design. The majority of the placed ICVs operate with a pressure drop of less than 100 psi with values of 10 psi or lower being common.

The flow rate through an ICV can be measured using either a conventional test separator at the surface or by a downhole or surface multi-phase flow meter. The technique is to close all ICVs except one will be open, which will be tested. But, the disadvantage of this technique is that the measured flow rate is not representative of the actual flow rate when the well is producing normally with commingled flow from different zones. This is especially true if the valve is operating under sub-critical flow. Here, the pressure downstream of the valve i. e. inside the tubing, is affecting the behavior and the response of the valve.

2.4.3.1 Where less likely to find IWsT value

Installation of Intelligent Wells may not be justifiable in mature field developments with limited reserve and low rate wells e. g. land operations and large platforms with easy well access. These often show limited scope for value creation since only well optimization is possible and IWsT completions may extremely increase project cost.

For our field case the (STOIIP) Stock Tank Oil Initially in Place is quite high if we consider the most likely case which is 288.88 (STB) for oil and 94.36 (SCF) for (GIIP) Gas Initially in Place. And based on the well test date the recovery expected to be high, hence the implementation of IWCs is recommended in BE field.

Summary

With the introduction of IWT technology, the productivity of hydrocarbon can be greatly improved, due to the combination of better control of reservoir drawdown and better control of production flow rate from many zones in case of commingled reservoir. The better control over the hydrocarbon productivity by IWT also minimizes the viscous fingering problems which commonly occur in waterflooding or gas injection and delay the water breakthrough as well.

CHAPTER 3

METHODOLOGY

3. 1 Research Methodology

Figure below shows the research methodology for this project:

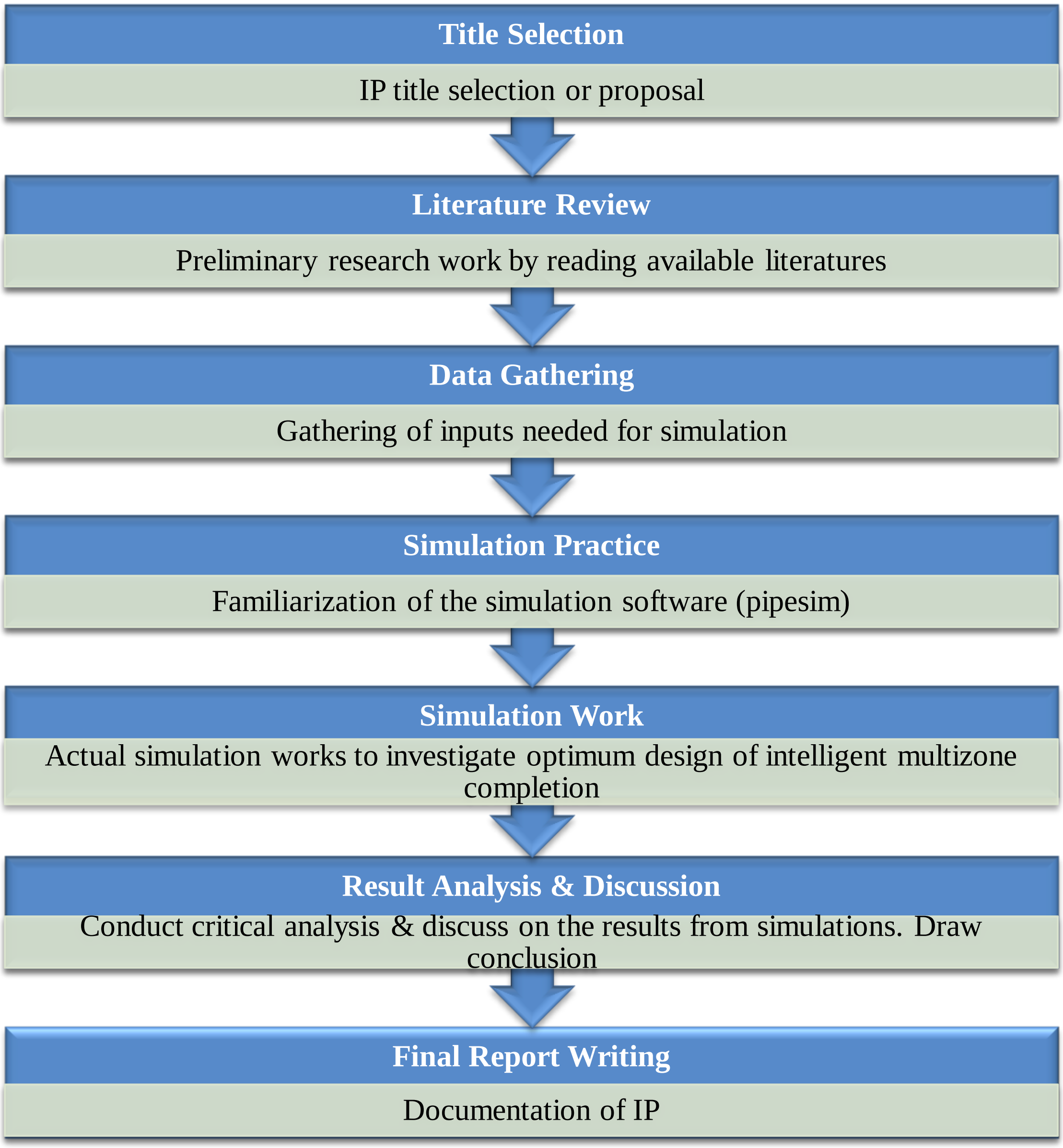


Figure 3.1: Schematic diagram of project flow

The subsequent paragraphs describe the methodology of this project in brief. Following the selection of project title, the project started with brief overview of Berlian East field and some review of the SPE papers and other online journals related to IWT technology. The objective of this stage is to gain thorough understanding on the concept of IWT and thus forming strong basic knowledge to assist the future study.

The next stage is to collect the parameters and data for the inputs for the studies, mostly from Berlian East field data. The data collected are the reservoir and rock properties, as well as the description of the reservoir. From the literature review, the collected data and information will be key-in into the simulator, namely PIPESIM software.

The simulations are conducted to investigate the performance of different IWT in case of using it in a multi-layered reservoir and to assess the reservoir productivity with IWT compared to the conventional completion. Subsequently, upon the acquisition of the simulation results, analysis on the trend behaviors and graphs will be conducted to discuss the impacts of ICV choking policies on the optimization of productivity using nodal analysis.

The project activities for this project can be generalized into 4 groups/stages:

a) Literature Review & Data Gathering

b) Simulation/Modelling

c) Analyses

The first item, literature review was conducted in chapter 2 and the rest of the stages were carried out in next chapters. These activities will be elaborated in details in the following sections.

3.2 Literature Review & Data Gathering

Data collection was implemented concurrently with literature review. For reservoir well test data, the focuses are the reservoir pressure, absolute permeability, oil rate, perforation interval, skin factor, productivity index and etc.

Well test are usually carried out by taking pressure measurements in the well at the start and during production. Based on the well test results data in Table 3.2, it can be concluded that the test design is a short term test design (ranging from 7 hours to 11.7 hours).

Actually, many parameters in this table such as average reservoir pressure and temperature recalculated again at the actual vertical depth, which occur in the perforations interval (1346.6 ft and 1334.5 ft) for both layers M 2/3 and M 7/8 respectively.

In fact, layers M 2/3 and M 7/8 are the subject of this project. And the aim here is to commingle both of them in a single well using “smart completion”, in order to optimize the productivity of the field with fewer wells.

Table 3.2: Well Test Data of Berlian East Field. [2]

Well	P1	P2
Sand	M 7/8	M 2/3
Test interval (ft)	1346.6-1329.0	1334.5-1337.7
Reservoir Pressure (psia)	1913	1968
Oil rate (stb/d)	2960	299
Gas rate (mmscf/d)	4.01	0.09
Tubing size (inch)	3 ½”	3 ½”
Sep GOR (scf/stb)	1389	1301
Water cut (%)	0	0
FTHP (psig)	463	223
FBHP at gauge (psig)	1718	1253
FTHT (F)	108	100
Flow period (hrs)	7	7.4
Sand (pptb)	traces	traces
Oil gravity (API)	41.7	35
Drawdown (psi)	250	660
Prod Index, PI (b/d/psi)	4	0.5
kh (mD,ft)	27217	1259
Skin	1	3
k (mD)	805	120
Oil viscosity (cp)	1.76	1.75
Perforation interval (m)	3	3
Reservoir temperature (F)	211	213

The data gathered in this section were used as the inputs for the subsequent activity, namely simulations.

3.3 Simulation/Modeling

The simulations were carried out using a simulator known as the PIPESIM.

PIPESIM software is a steady-state, multiphase flow simulator for the design and diagnostic analysis of oil and gas production systems. PIPESIM software tools model multiphase flow from the reservoir to the wellhead. PIPESIM software also analyses flowline and surface facility performance to generate comprehensive production system.

With advanced modelling algorithms for nodal analysis, PVT analysis, gas lift, and erosion and corrosion modelling, PIPESIM software helps you optimize your production and injection operations. Figure 3.2 below shows the interface of the PIPESIM software:

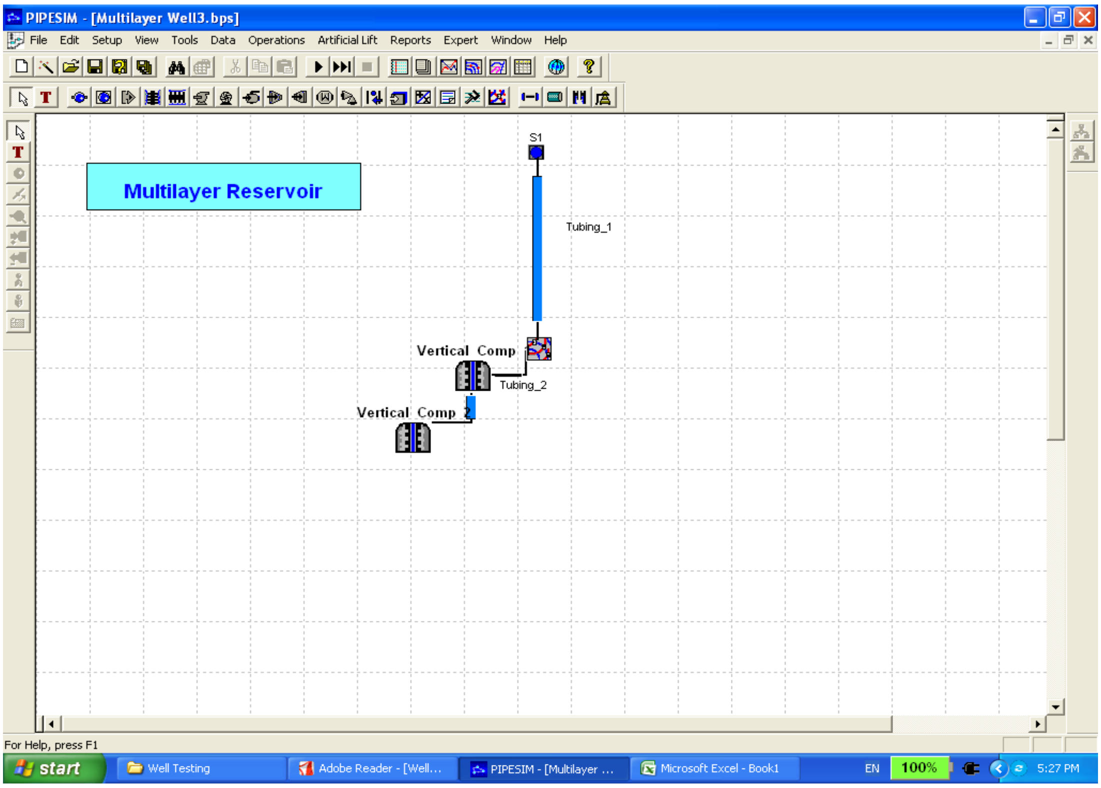


Figure 3.2: Interface of PIPESIM software simulator

Further discussion on the PIPESIM simulations will be presented in the subsequent sections.

3.3.2 Reservoir Modelling

The first step in the simulation is to create a reservoir model and include all the reservoir data gathered from the well test data, the Figure 3.2 shows the reservoir model components with two layers M 2/3 and M 7/8, nodal analysis, production tubing and tubing head pressure choke.

The next step is to match the model with the actual reservoir oil production flow rate Q and reservoir pressure P_r through the nodal. Figures 4.1 to 4.4 show that, and the main purpose here is to minimize the uncertainties of the model as much as possible in order to get correct sensitivities in the subsequent simulations. Table 3.3 shows the difference between the actual reservoir data and the data result obtained from the simulation model for both layers M2/3 and M7/8. As we can see from this table is the results are almost similar, so the model is accurate and errors will not significantly affect the results.

Table 3.3 : Shows the difference between the actual reservoir data and data result from simulation model

Well	**P1 (M 7/8)**		**P2 (M 2/3)**	
Reservoir Parameters	Oil rate (stb/d)	Reservoir Pressure (psia)	Oil rate (stb/d)	Reservoir Pressure (psia)
Actual reservoir data	2960	1913	299	1968
Result from model	2968	1910	282.15	1965

The next step is to commingle both layers M 2/3 and M 7/8 in one conventional single well (Figure 4.15 in the appendix shows the conventional dual completion string), rather than two separate wells, then get the oil flow rate Q for both layers. And figure 3.3 shows the fluid cross flow between two layers M 2/3 and M 7/8. The reasons behind this cross flow will discuss in details in the next section.

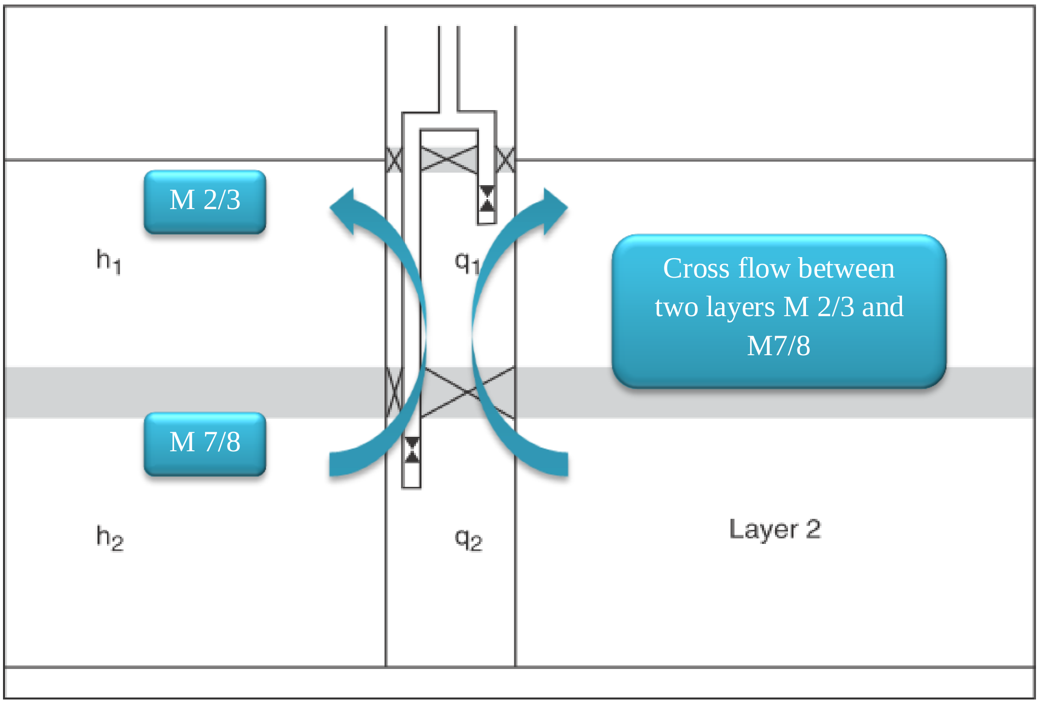


Figure 3.3: Fluid cross flow between the two commingled layers M 2/3 and M 7/8

The next section is to implement the intelligent completion IWC in order to prevent the cross flow between layers and optimize the hydrocarbon flow rate by choosing the right choking policy of ICV, and these will discuss more deeper in the results section of (Chapter 4).

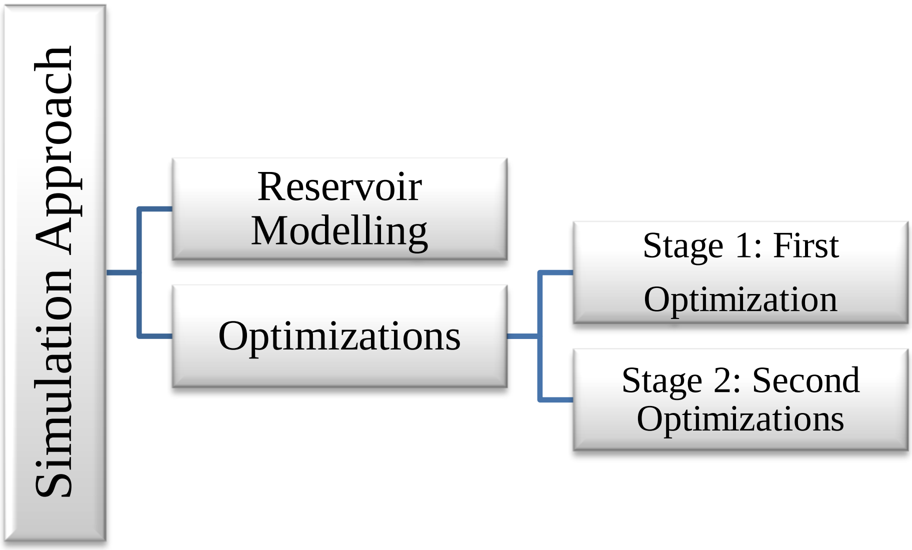


Figure 3.4: Simulation approach

3. 4 Analyses

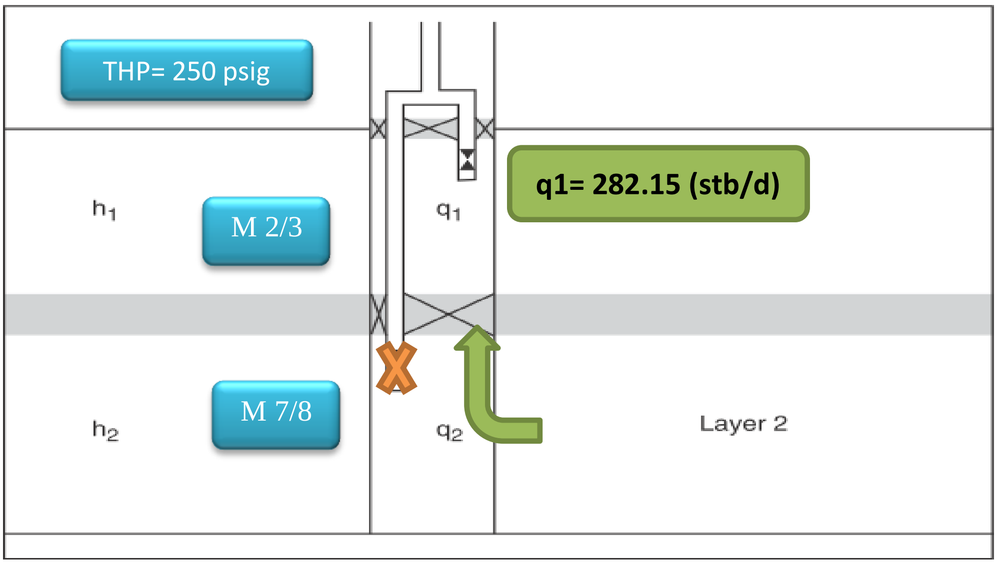
This is the core of the IP, where the simulation outcomes and results obtained from the simulations are critically analyzed in order to fully understand the trends behavior of reservoir. Strong basic knowledge and understandings on the topic are required to implement this technology successfully. The results of analyses for this project will be presented in Chapter 4.

CHAPTER 4

RESULT AND DISCUSSION

The objective of this project is to simulate and determine the production performance of different choking policies in order to prevent cross flow from one zone to another in same time optimize the production by finding the suitable choking size of the ICV. To be able to do that a history matching of the simulation model with the real field model is the first step that should work on it, in order to get a useful model with less error in the next simulation results.

From the Figure 4.1 and 4.2 which show the matching of production flow rate from the upper and bottom layers M 2/3 and M 7/8 at tubing head pressure of 250 psig for M 2/3 and 463 psig for layer M 7/8. Hence by changing some parameters in the simulator such as perforation interval and placement we can see that the production flow rate is almost similar to the given well test data as we showed before in the previous section (table 3.3). Therefore the model is accurate and the results are correct with minimum uncertainty.



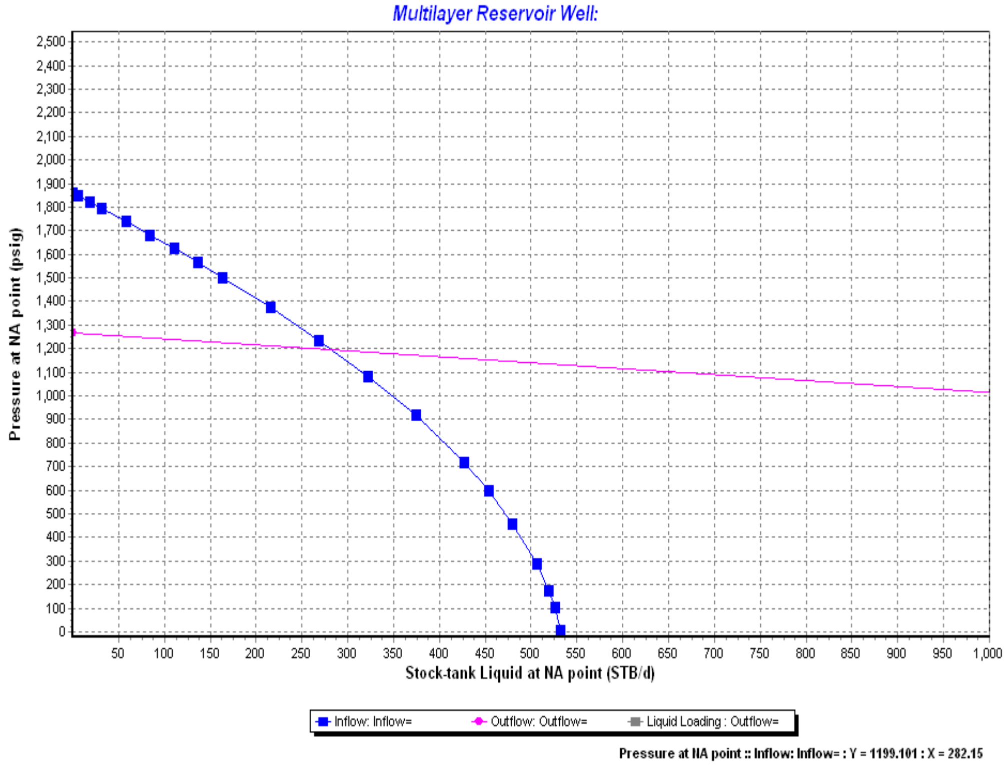
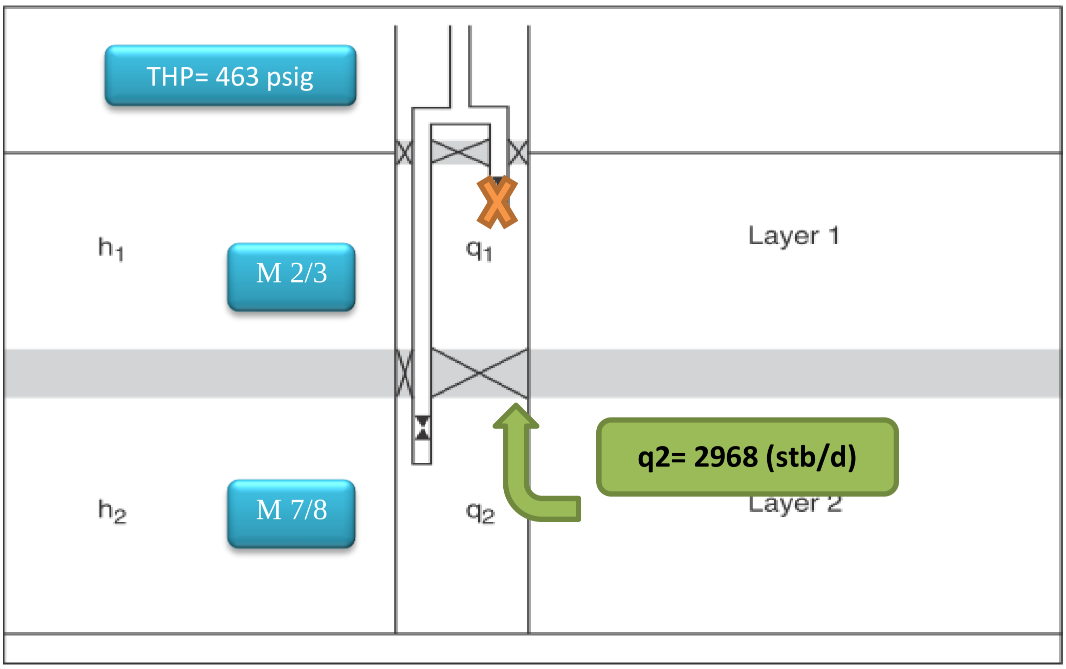


Figure 4.1: Matching of production flow rate from the upper layer at tubing head pressure of 250 psig



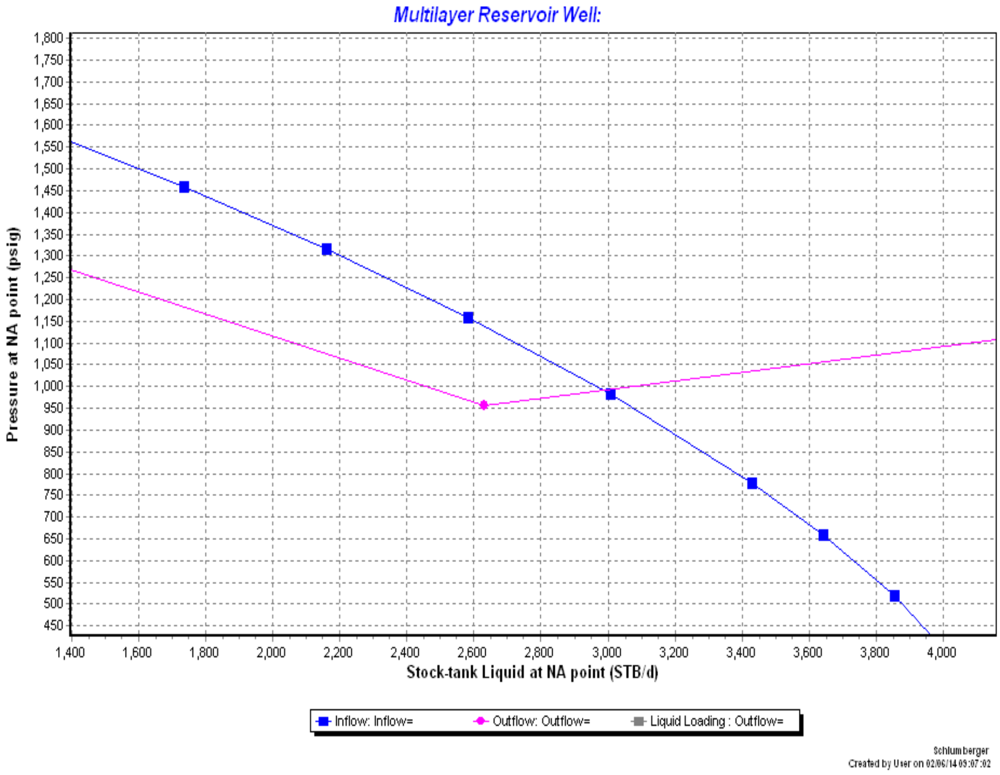
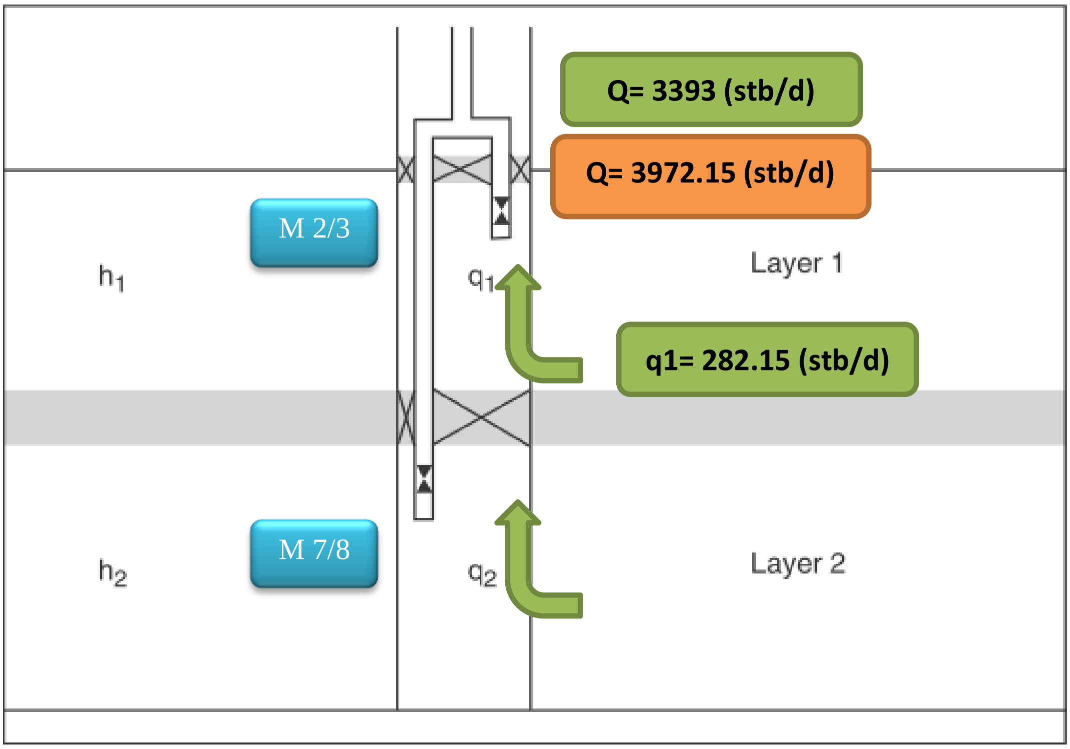


Figure 4.2: Matching of production flow rate from the bottom layer at tubing head pressure of 463 psig

From Figure 4.3, which is showing the production flow rate from commingle layers M 2/3 and M 7/8 at tubing head pressure of 250 psig we can see that the oil production is 3300 stb/d, however the oil production rate should be the sum of the two layers together with the value of 3350 stb/d. In fact this is occurred because the cross flow between the two layers, when the commingling occurs and tubing head pressure decrease, the production from the lower zone M 7/8 will increase due to the decreasing in tubing head pressure for this layer which was 463 psig. Then the cross flow between the two layers will occur due to the direct connection among them, and this will give lower productivity from the both layers by shutting off the upper layer and flowing on the bottom layer. So the best way here to handle this problem is to apply the inflow control valve, which prevent the upper layer from cross flow and the tubing head pressure can be lowered to any value, hence the flexibility of the well design will increase and the oil production rate as well.



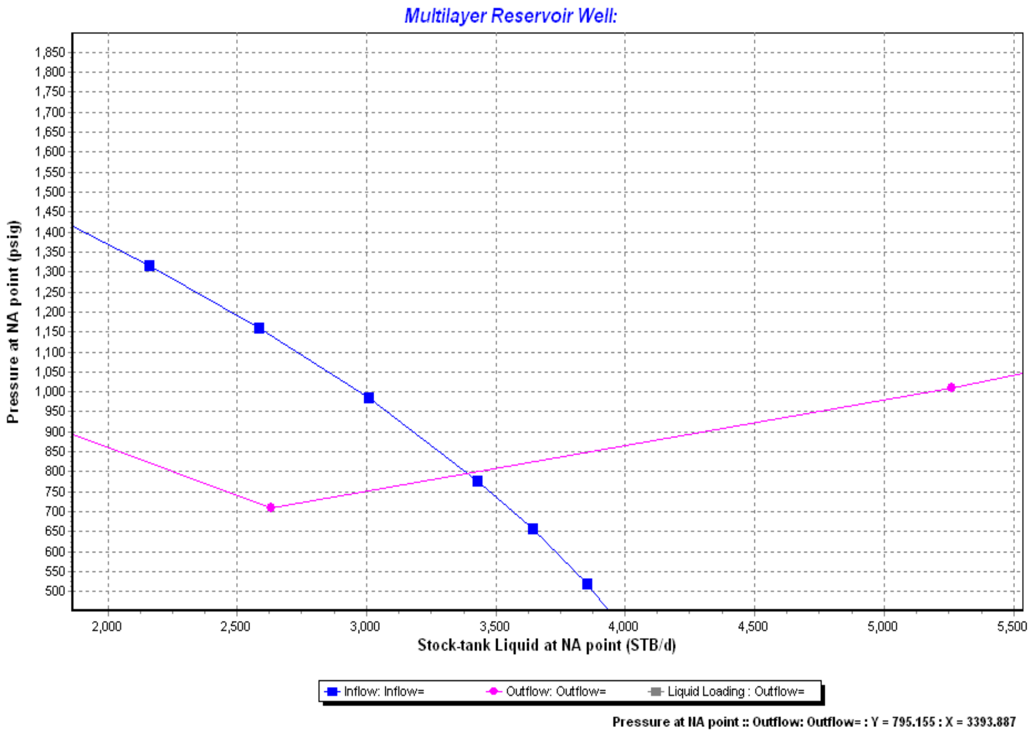


Figure 4.3: production flow rate from commingle layers at tubing head pressure of 250 psig

Figure 4.4 shows the fluid productivity only from the bottom zone at the tubing head pressure of 250 psig, so as we can see the oil productivity is 3690 stb/d for the M 7/8 zone alone and from the previous commingled simulation result between two layers in Figure 4.3, we got only 3393 stb/d only for both layers together. But in fact it should be the sum of both flow rates from both layers which is 3972 stb/d, and that conformed that the cross flow has occurred.

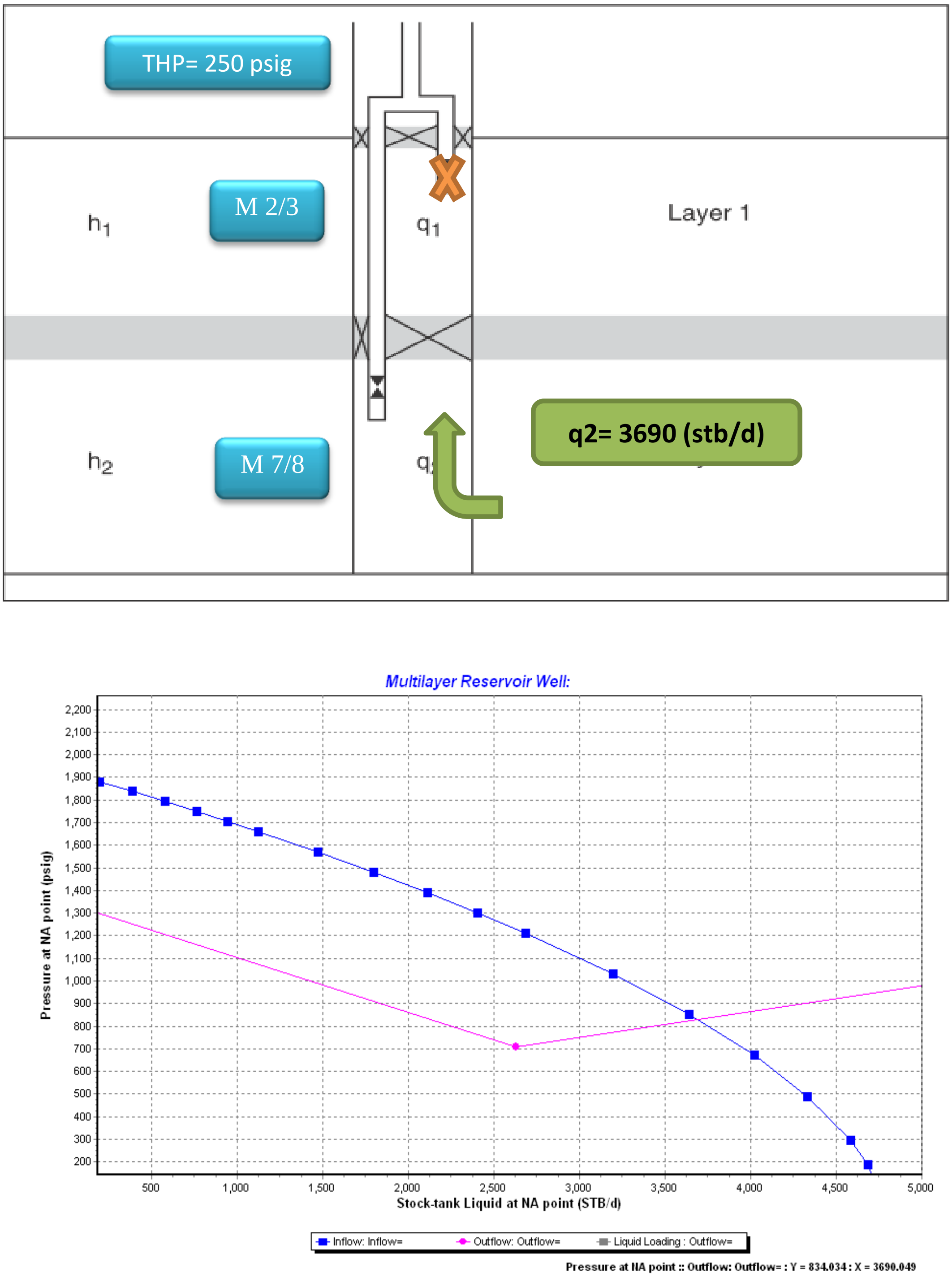


Figure 4.4: Matching of production flow rate from the bottom layer at tubing head pressure of 250 psig

Optimization 1: Choking Sensitivity

After the implementation of the ICV, we have done some sensitivity study in the level of the valves choking in order to get the optimum choking for the lower zone to tolerate it with this new tubing head pressure and prevent upper layer from the cross flow. Figures 4.5, 4.6, 4.7, 4.8 and 4.9 show different sensitivities for the ICV choking. The sensitivities were 5%, 10%, 15% and 20% from the total area of the tubing cross section area with the valve area of 4.444 mm, 8.9 mm, 13.3 mm, 17.8 m, while Figure 4.9 combines these four pictures together in one graph in order to make the comparison between them easier and clearer.

So from these figures we can conclude that the best chock for ICV is 20% from the total tubing cross section area which is 17.8 mm, Because it gives the highest productivity with tubing head pressure of 250 psia as we can see in Figure 4.5 (around 3690 stb/d) and without any cross flow between the two layers (upper and lower).

So with 17.8 mm of choking of the lower layer we can drive the production in optimum way, in same time the water breakthrough will not occur early, hence the field will have longer life time compared to the conventional completion system.

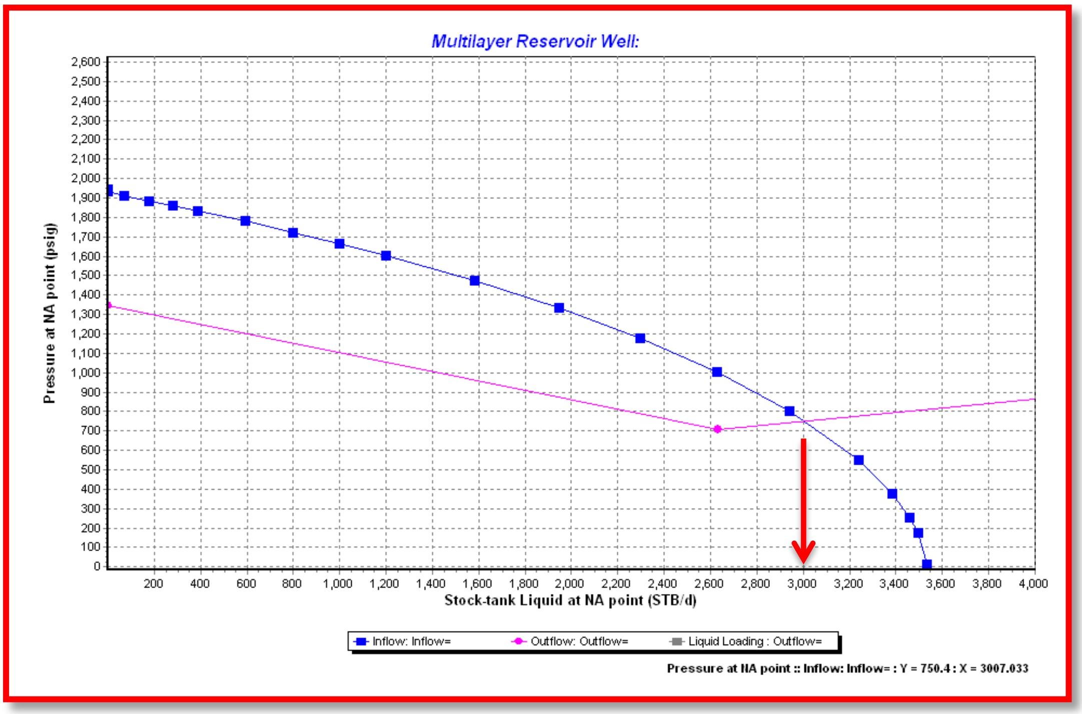


Figure 4.5: ICV choke size of 17.8 mm

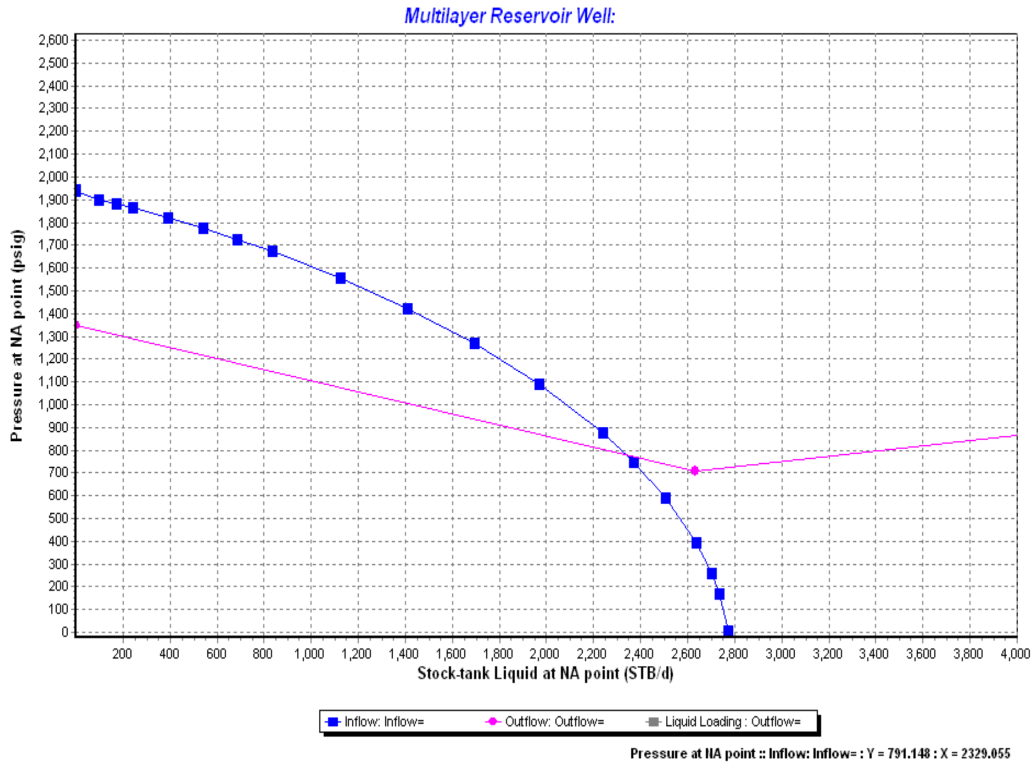


Figure 4.6: ICV choke size of 13.3 mm

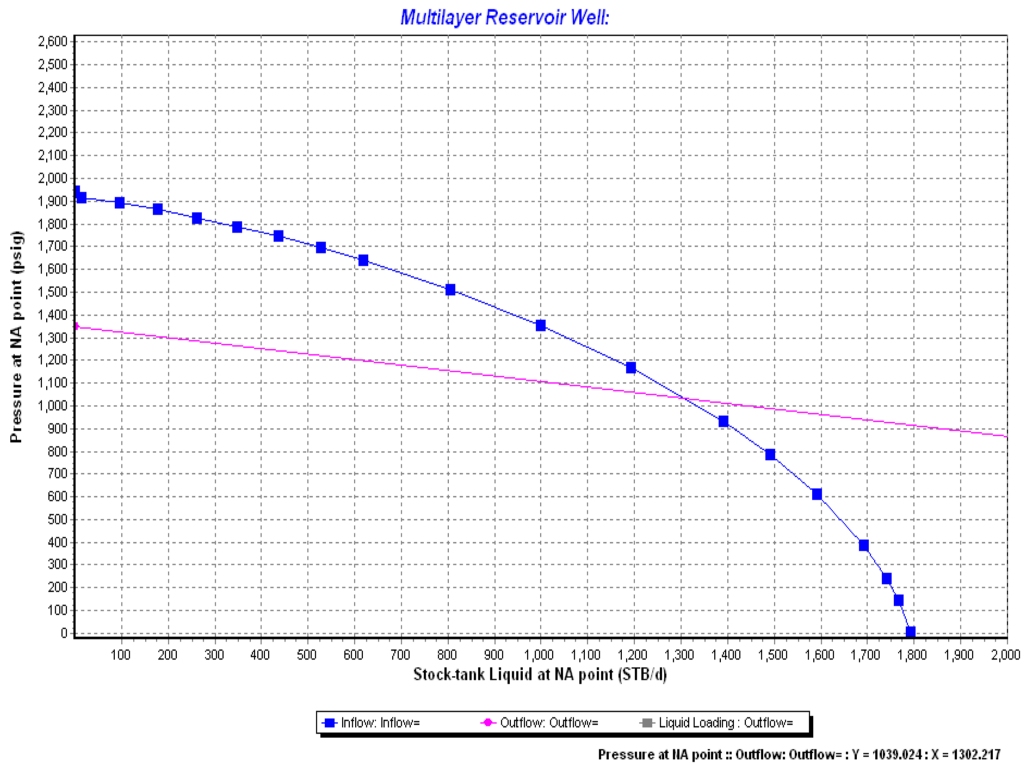


Figure 4.7: ICV choke size of 8.9 mm

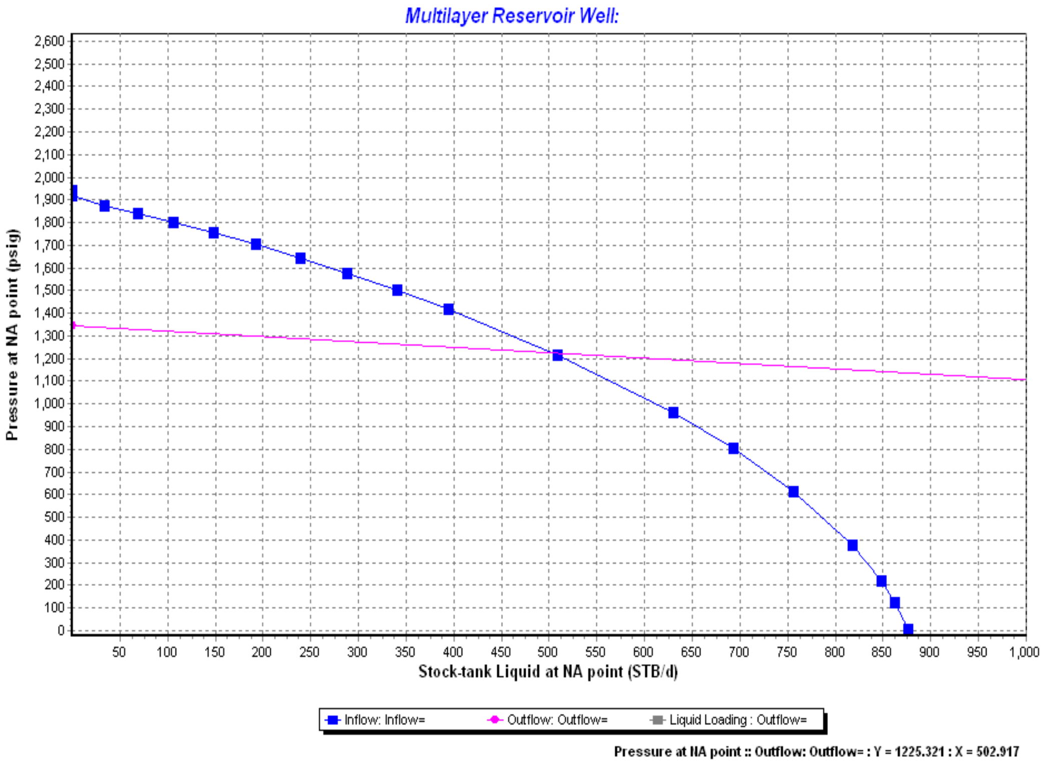


Figure 4.8: ICV choke size of 4.445 mm

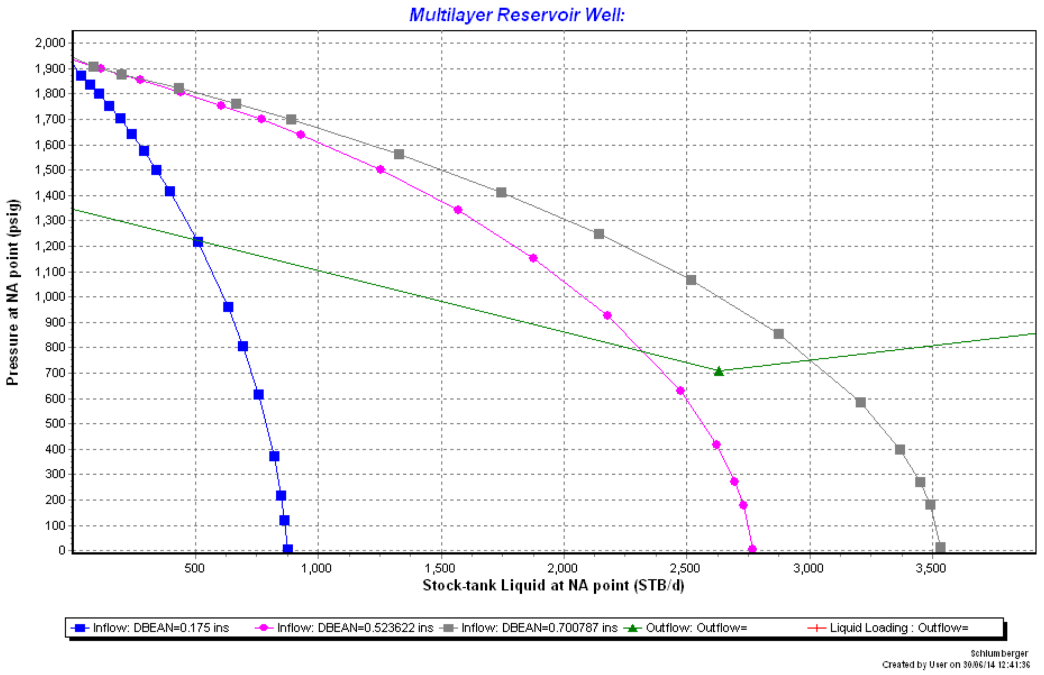


Figure 4.9: ICV CHOKE SIZE 0.175 IN (4.445 mm), 0.524 in (13.3 mm) and 0.701 in (17.8 mm)

Optimization 2: Tubing, Tubing Head Pressure and Pressure Depletion Sensitivities

Figure 4.10 shows tubing size sensitivity, which confirmed that the optimum tubing size for this specific well is $3^{1/2}$, however from the three figures which are Figure 4.11 (shows the tubing head pressure sensitivity for commingled zone), Figure 4.12 presents the pressure depletion for upper layer M 2/3 and finally Figure 4.13 that present the pressure depletion for lower layer M7/8. We can conclude that the suitable tubing head pressure in the future of the field that can conserve the same productivity from both zones is 150 psig after more depletion in level of reservoir. This result obtained after doing three sensitivities in level of tubing head pressure Figure 4.11, reservoir depletion pressure for both zones as we can see in Figure 4.12 and Figure 4.13 and tubing size.

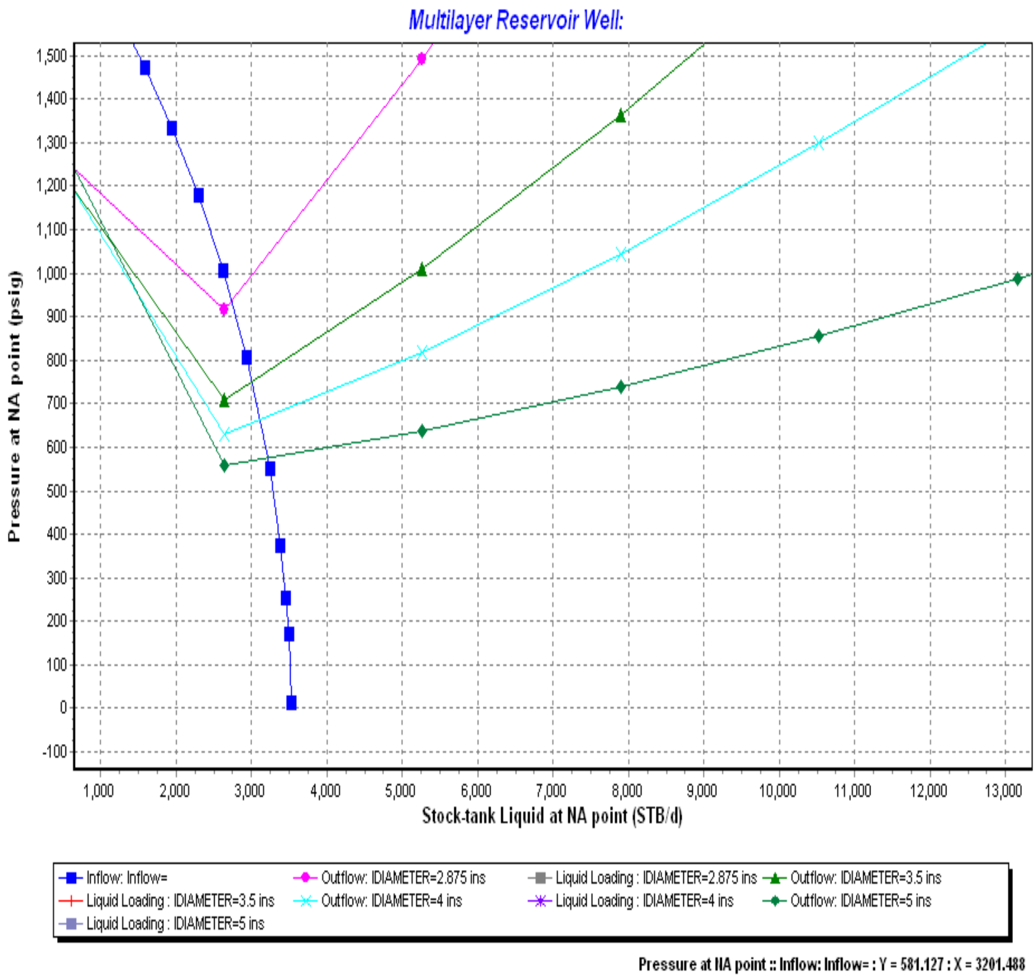


Figure 4.10: Tubing size sensitivity

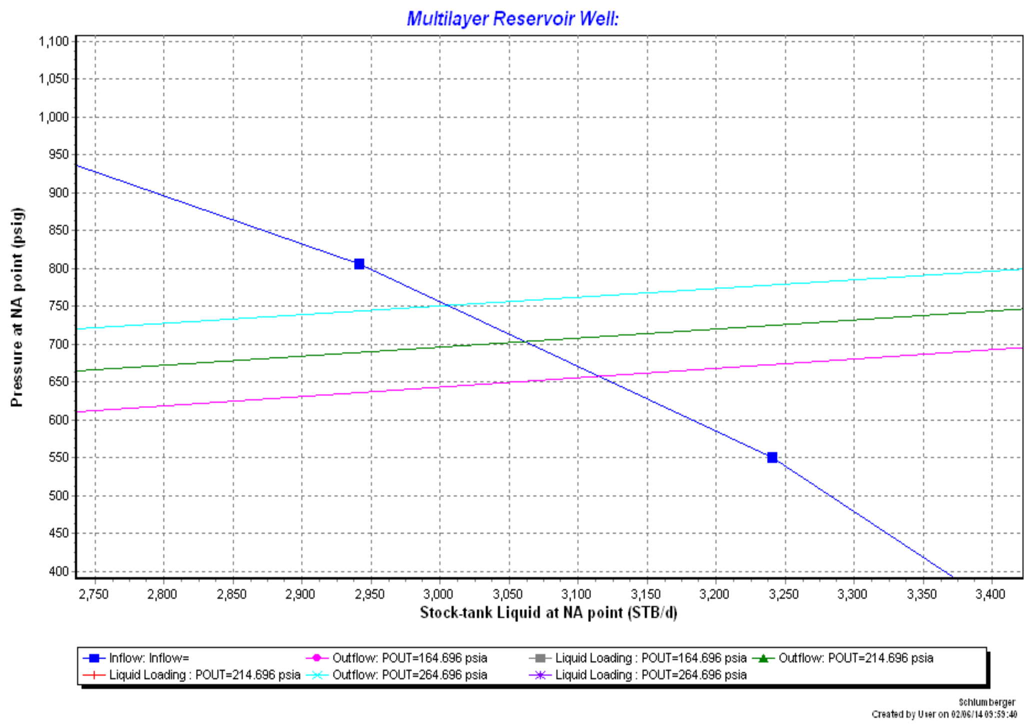


Figure 4.11: Tubing head pressure sensitivity for commingled zone

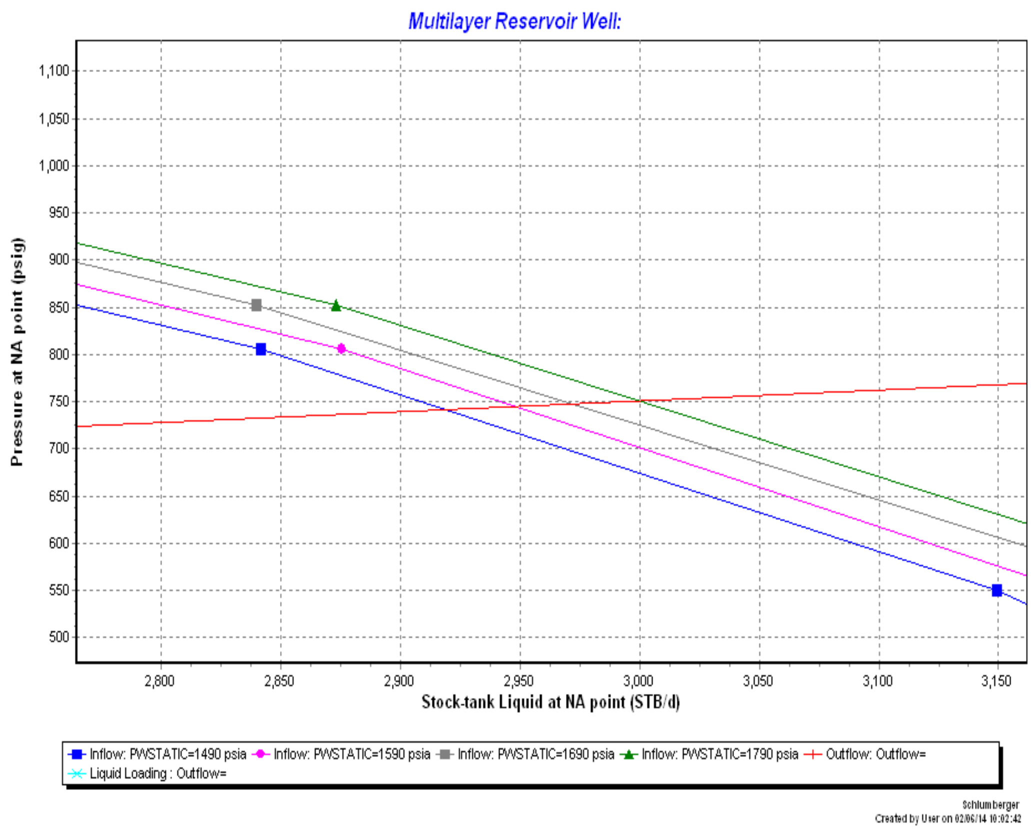


Figure 4.12: Pressure depletion for upper layer M 2/3

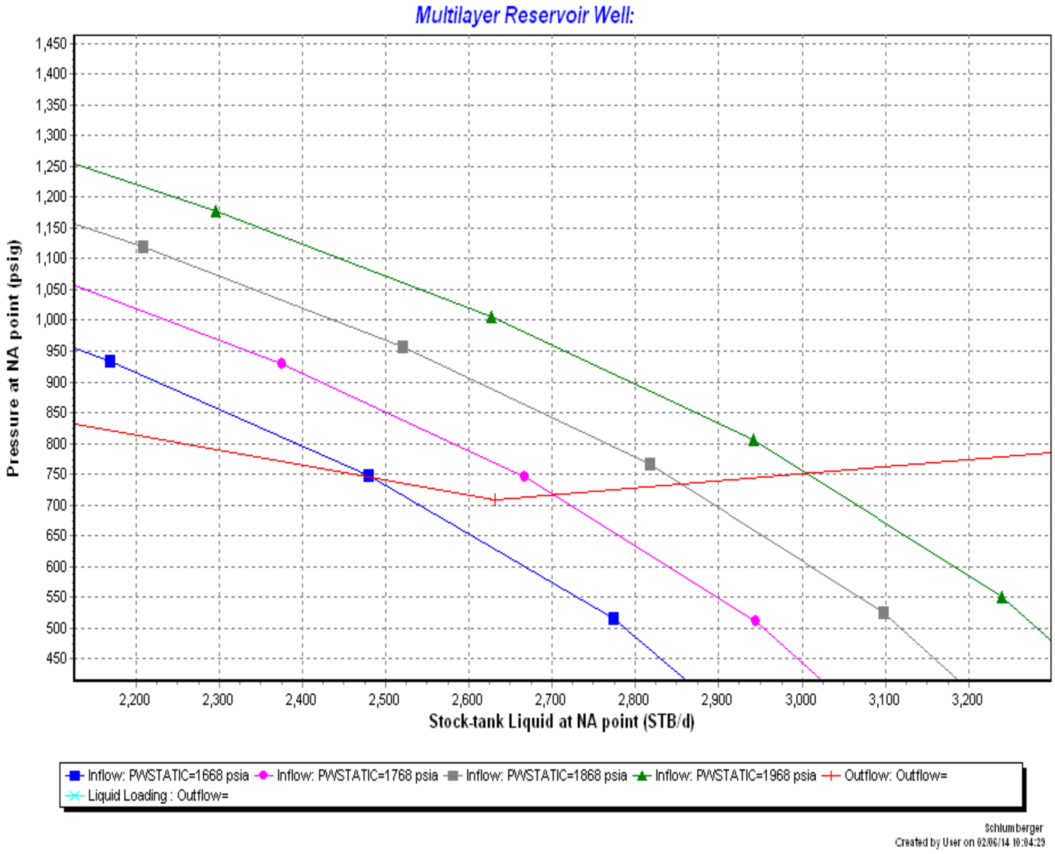


Figure 4.13: Pressure depletion for lower layer M7/8

So in the future of this field, some production enhancing like enhancing oil recovery (waterflooding, gas injection or WAG) is quite recommended in order to maintain the reservoir pressure and avoid lowering the tubing head pressure. Because 150 psia it may not suitable for the separator at surface (under the minimum), especially if the riser is too long in this case we need the push the fluid to reach the surface, hence pressure in maintenances Berlian East Field is highly recommended.

Economic benefit of IWT application

IWT application involves very high initial capital costs and complexity in the installation and maintenance stage. It is estimated that the cost for IWT varies between the range of USD 200k for a permanent downhole-gauge system to nearly USD 2.5M for fully specified multi-zone remote-controlled completion [13].

Several published papers mentioned on the lack of method to quantitatively define and measure value associated with the applications of IWT. The method that commonly practiced by most companies is the conventional method, which consists of Net Present Value, payback period and internal rate of return (ERR) analysis. However, often companies failed to quantify and justify the value of the IWT from the analysis of the mentioned methods. This is mainly due to the nature of IWT which leads to the underestimation of the value related with the technology.

Nevertheless, the accuracy of value justification is less important than the overall outcome resulting from the applications of the IWT, as long as the method used is consistent and reliable. Furthermore, if IWT can be proven to achieve an incremental gain i.e.: maximize oil productivity or minimize water production, there is no doubt that this system is better than the conventional system.

Since this study used a synthetic model, an appropriate economic evaluation could not be performed due to initially low OIP and total oil production. It has been proven that IWT has increased the production in this type of reservoir as compared to the conventional well.

In general, IWT contributes to the production process as a result of the following:

1. Removing or reducing the frequency of intervention required for the reservoir and production monitoring/optimization and enabling tuning or production, which will no longer be limited by control of surface facilities

2. Increasing oil productivity in the event of inaccurate drilling techniques or data interpretations during the exploration stage, specifically in stratigraphic trap reservoirs.

3. Increasing ultimate oil productivity and production by zonal/branch or inflow-profile optimization facilitated by timely remote-control inputs

4. Reducing gross fluid handling, waste products, surface hardware costs (e.g.: lines, separation, and metering), manpower, and support service.

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1 CONCLUSIONS

This project discuss the application of IWT in one well in a real field example. This application shows limited increase in oil production using IWT compared to the previous publication where the synthetic models were used and high productivity increase was achieved.

a. With the correct choking policy of inflow control valve, the increase in the oil production can be achieved in a commingled well,

b. Crossflow nature of the reservoir layers prevents the control on each zone independently.

c. Installing the two ICVs was beneficial in terms of balancing the drawdown across the commingled wellbore, which help to produce both zones at the similar oil rate, without any cross flow between M 2/3 and M 7/8 layers.

There is a potential value creation through development of a multilayer reservoirs using IWT compared to a conventional well development. The value was created by commingling separated reservoirs (allowing a longer well producing life)

5.2 RECOMMENDATIONS

Due to the time limitation of this study, this report was emphasized on the basic simulation-based optimizations studies. However, there are many areas need more research to be done, such as:

1. This study covers a field cases reservoir management challenges. There are still further types of reservoirs where IWT can deliver value from different sources e.g. fractured reservoirs and tight reservoirs. Similar studies as to those discussed here can be carried out in order to show that value using real field examples.

2. This study was focused on applying Intelligent Wells in either vertical or horizontal wells. Multi-lateral wells are now becoming a preferred technology that can be used in conjunction with IWT. It should be studied whether the results found from this study can be directly applied to multilateral wells.

3. Geological uncertainty was totally ignored in this study, even though it is recognized that it can play a key role on designing and operating the ICVs.

4. Development of improved optimization techniques holds the key to quicker completion of studies of the type reported here and to the development of operational optimization tools based on real-time data. In particular, the GAP optimization tool needs to be improved in order to minimize the number of system oscillations.

5. All optimizations and uncertainty studies were only include limited completion options. Therefore, it is necessary to include alternative completion options such as multilateral or horizontal completion at various geological scenarios.

6. This study was based on the simple layered reservoir model. In actual, layered reservoirs often, involve different and more complex geological scenarios. Other reservoir or geological elements should also be taken into account, these include:
    - Reservoir geometry,

- Fluid composition,
- Fluid distributions in the reservoir,
- Driving forces.

7. Perform detail IWT value analysis based on applicability in this type of reservoir. The analysis should include the failure probability or valve reliability, comprehensive economic valuation, etc.

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APPENDIX

Overview of intelligent well completion

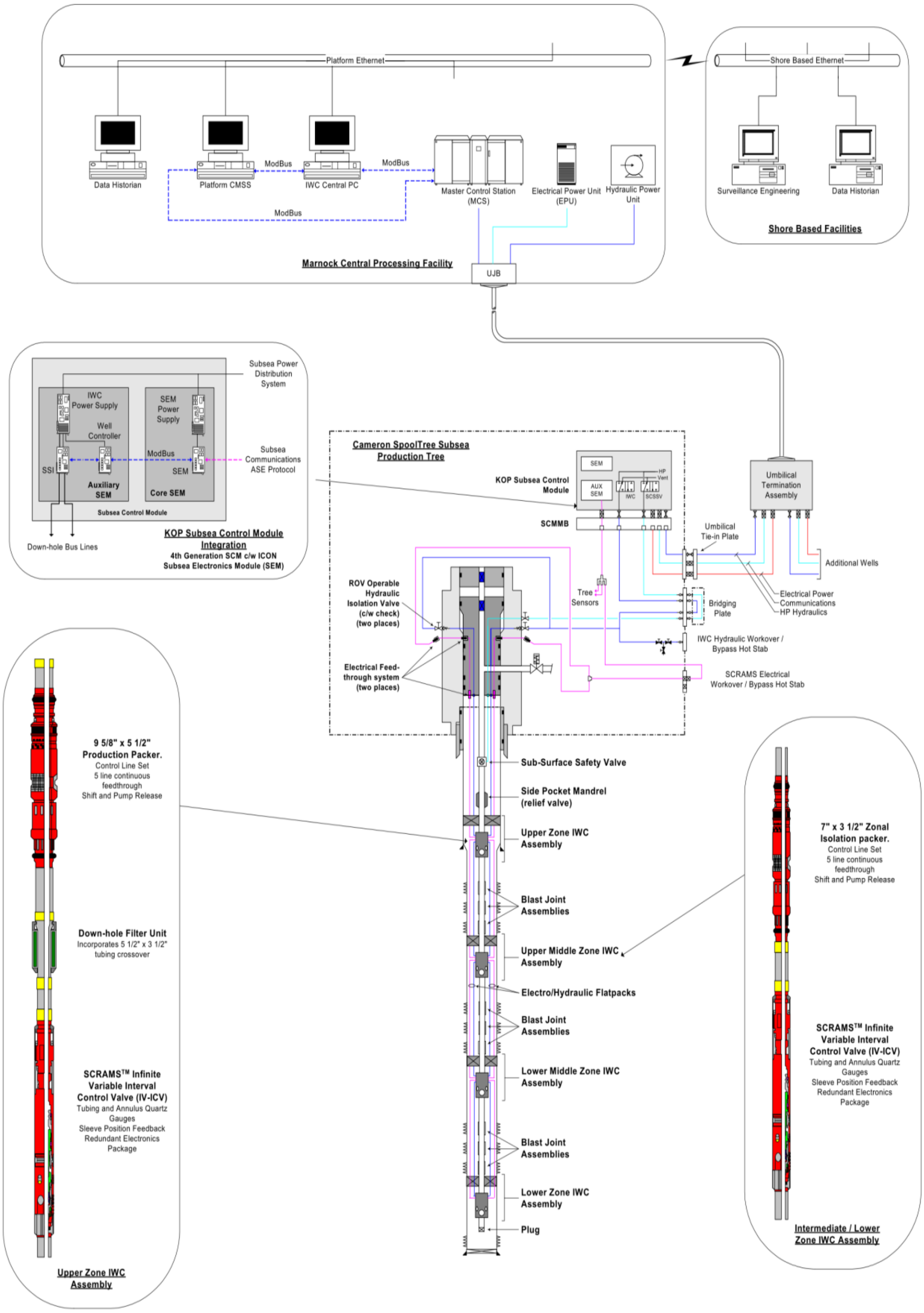

Figure 4.14: IWC Implementation Overview

Convectional Completion design

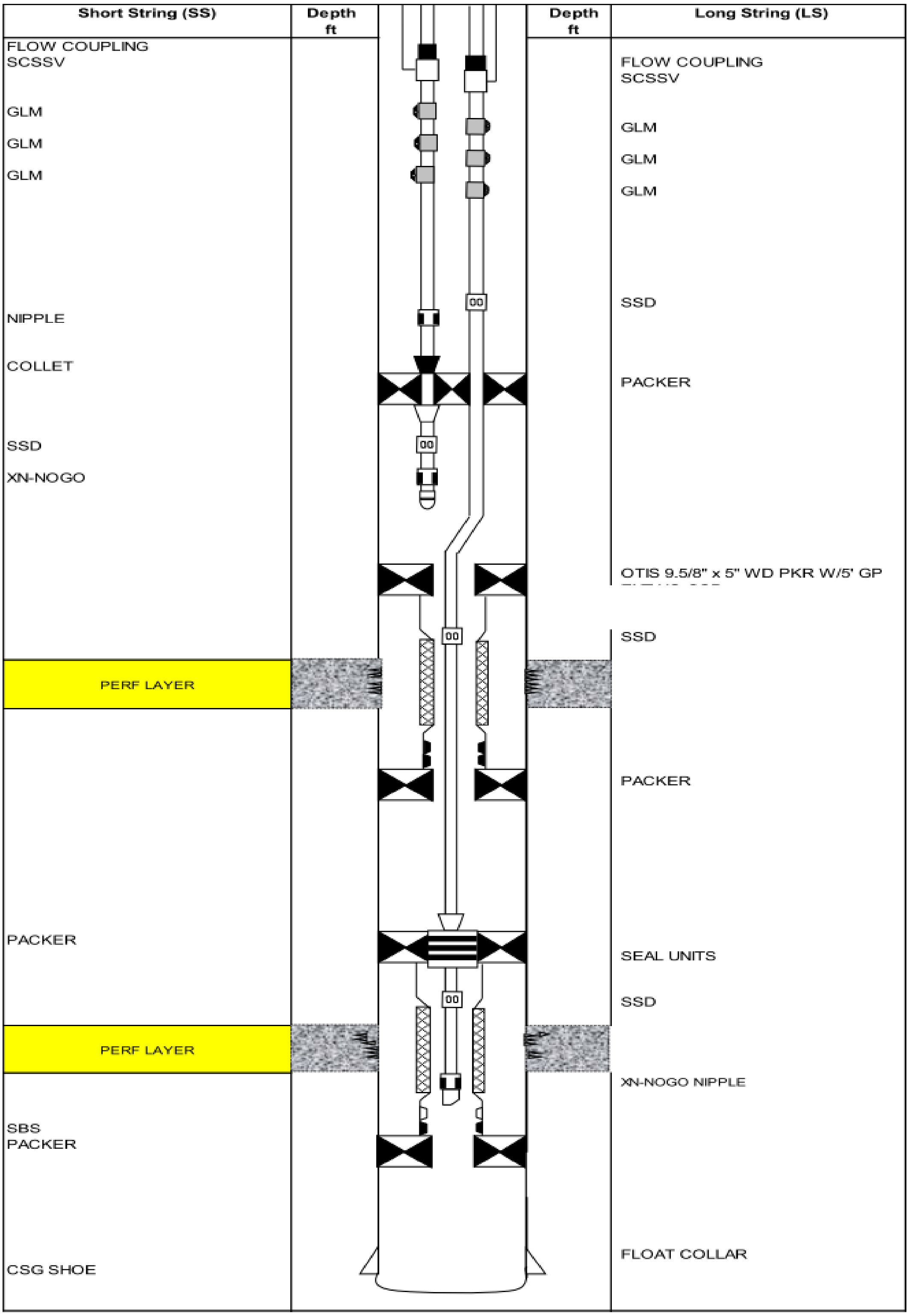

Figure 4.15: Well Schematic for Dual String Oil Producer

Standard design of the Intelligent Well Completion

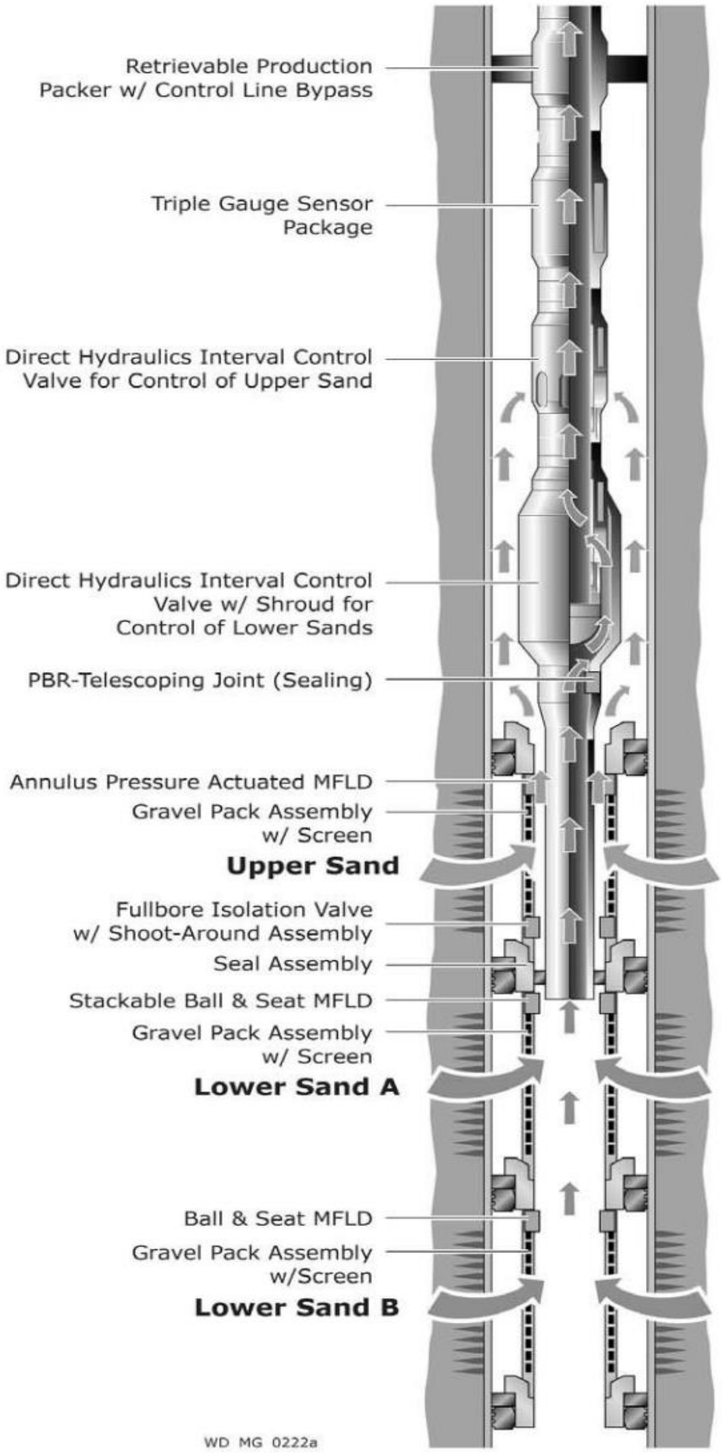

Figure 4.16: Intelligent Well Completion Example in a multilayer reservoir